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No. 680

IN THE

Supreme Court of the United States

OCTOBER TERM, 1970

CONTINENTAL OIL COMPANY, ET AL.,

Petitioners,

v.

FEDERAL POWER COMMISSION,

Respondent.

APPENDICES TO PETITION FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FIFTH CIRCUIT.

CONTINENTAL OIL COMPANY
Tom Burton
P. O. Box 2197
Houston Texas 77001

MOBIL OIL CORPORATION
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FIDELITY PRINTING COMPANY, INC., HOUSTON

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APPENDIX A

Opinion of the United States
Court of Appeals for the Fifth Circuit
No. 27492, et al.
Southern Louisiana Area Rate Cases
(March 19, 1970)

IN THE

United States Court of Appeals

FOR THE FIFTH CIRCUIT

No. 27492, et al

SOUTHERN LOUISIANA AREA RATE CASES

AUSTRAL OIL CO., ET AL,

Petitioners,

versus

FEDERAL POWER COMMISSION,

Respondent.

Petition for Review of Orders of the Federal Power Commission (Texas Case)

(March 19, 1970)

Before THORNBERRY, COLEMAN and MORGAN, Circuit Judges.

THORNBERRY, Circuit Judge: This is a proceeding to review orders of the Federal Power Commission setting maximum rates for wellhead sales of natural gas produced in the Southern Louisiana area. Thirty-seven producer petitioners challenge the rates as too low.[1] Eight pipeline companies are also involved in

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[1] In discussing the issues in this case, we have usually simplified the positions of the parties by considering them as producers, consumers, and the Commission. Our review of the case, however, has taken into account subtler differences among the

the proceedings, and they concur with the producers that the rates are too low.[2] On the other hand, certain consumer interests have intervened and attack the rates as too high.[3] The Federal Power Commission presents a third position by arguing that its orders should be sustained in full.[4] The result of this trichotomy of conflicting positions — producers, consumers, and the Commission — is a case as complex as it is important.

We have determined that the orders of the Commission should be sustained in full. We add, however, that

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parties. Most of the producers, for example, have joined a single group, the Amerada group, in briefing their argument, but others have chosen to present their arguments separately. Particularly conspicuous among these separate petitioners are several small producers, and we have treated their special arguments herein. The method of presentation is a question for the parties themselves. We think, however, after considering this case, that it is to the great advantage of the parties in a complex, multi-party case to aggregate their arguments in so far as possible.

[2] The pipelines purchase gas from the producers, and it seems anomalous at the outset that they are arguing that prices are too low. The Commission found that the inelasticity of market demand for gas at the consumer level "tends to make price a second level consideration" to pipelines. 4 Joint Appendix, pt. 1, at 533d (Commission's opinion). Pipelines sometimes own production factors as well. A significant reason for the pipelines' alignment here, however, may be simply that they are concerned that the price level will not elicit sufficient supply for their needs. At oral argument, they represented that informal rationing procedures among pipeline purchasers were now in effect and that formal agreements might be necessary in the future.

[3] These parties include the New York Public Service Commission and the Municipal Distributors Group, a group of municipally owned gas distribution systems.

[4] It is supported in this position by the Associated Distributors Group (ADG) of intervenors, a group of privately owned local utility companies.

this affirmance does not reflect full satisfaction with the performance that the Commission has turned in, but rather a recognition that the process of producer regulation is a difficult one that the Commission must have latitude to adapt to changing conditions. In the section of this opinion that immediately follows, we describe this process, together with the legal events that have led to its development, and set out the Commission's actions in the cases before us. In a second section, we deal with the consumer arguments that the rates are too high. The third section takes up the producer arguments that the rates are too low. Herein, we discuss what we believe is the most serious problem presented by these cases: The possibility that the Commission has not adequately considered the problem of new gas supply in relation to demand. There is evidence of a serious supply deficiency. Fourthly, we summarize our conclusions and indicate improvements that should be expected in the regulatory process. In this final section, we also consider the stay that has prevented the Commission's orders from going into effect through this stage of review.

I. THE PROCESS OF AREA REGULATION AND THE COMMISSION'S OPINIONS

The beginnings of producer area regulation were inauspicious. Ever since the enactment of the Natural Gas Act in 1938,[5] the FPC has had the responsibility of regulating sales by interstate pipeline companies, but it was not until 1954 that the Supreme Court held in *Phillips Petroleum Co. v. Wisconsin*,[6] that the Act also

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5 15 U.S.C. § 717 *et seq.* (1963); 52 Stat. 821 (1938).
6 347 U.S. 672, 74 S.Ct. 794, 98 L.Ed. 1035.

gave the Commission power to regulate sales by independent producers at the wellhead. The Commission was convinced that producer regulation would be impractical and consequently was reluctant to assume its new role.[7] Congress was willing to amend the Act to exclude producers. But the aftermath of the *Phillips* decision, as one commentator has described it, included an accident of history that left the Commission still faced with its difficult new duty:[8]

> Congress immediately responded [to *Phillips*] by passing an act declaring that the 1956 Congress did intend complete exclusion of independent producers, and suggesting rather strongly that the 1938 Congress probably did so as well. Whereupon the President, who strongly supported the 1956 act, vetoed it for reasons unrelated to the merits of the arguments of either the Court or Congress. It has taken the eight years since 1954 for the industry and the FPC to realize that they must mount this unbroken nightmare born of stalemate out of avarice and ride it if they are to move at all.
>
> The Commission was as hopeful after 1954 that this new-found, unwanted jurisdiction would vanish as it had once been fearful of

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[7] *See* F.P.C. Ann. Rep. 176-77 (1955); 36 F.P.C. Ann. Rep. 10 (1956); 37 F.P.C. Ann. Rep. 17-18 (1957); 39 F.P.C. Ann. Rep. 12-13 (1959).

[8] Johnson, *Producer Rate Regulation in Natural Gas Certification Proceedings: CATCO in Context*, 62 Colum. L. Rev. 773, 783 (1962); *see also* M. Merrill, The Public's Concern with the Fuel Minerals 104, (1960).

its coming. The record it has amassed that such regulation will not be successful is formidable.

Both economists and lawyers have questioned the soundness of direct producer price regulation,[9] but there is also support for the need for producer regulation of some type[10] and, whatever its merits, the law

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[9] *See, e.g.*, M. Adelman, The Supply and Price of Natural Gas 39 (1962); P. McAvoy, Price Formation in Natural Gas Fields 265 (1962); E. Neuner, The Natural Gas Industry 280-90 (1960) (recommending that contracting, behavior rather than price be regulated, in light of a conclusion that industry structure, at least, is competitive); Cram, *Introduction to the Problem of Developing Adequate Supplies of Natural Gas*, in Economics of the Gas Industry 24 (Southwestern Legal Foundation ed. 1962); Kail, The Evolution of Area Gas Pricing and Its Effects on the Natural Gas Industry 18-22, January, 1968 (unpublished thesis in University of Texas Library); Kitch, *Regulation of the Field Market for Natural Gas by the Federal Power Commission*, 11 J. Law & Econ. 243 (1968); *cf* Kitch, *The Permian Basin Area Rate Cases and the Regulatory Determination of Price*, 116 U. Pa. L. Rev. 191, 194-99 (1967) (concluding that area rate regulation resembles wartime price control).

These and other authorities, however, are relevant only to the quasi-legislative function of the Commission in deciding how producers are to be regulated. The decisions of the Supreme Court definitely indicate that the Commission has a responsibility to take the steps necessary to assure that wellhead prices are in the public interest. The Commission does not have to employ the area rate method, or for that matter regulate price directly at all, but it has chosen to fulfill its duty in that manner here.

[10] The Commission concluded that there was an absence of effective competition in wellhead sales. This absence seems to be strongly evidenced by a rapid spiral of price increases over the years from 1950 to 1958, when the price went from less than 9 cents per Mcf to a peak of 24.05 cents. This spiral was apparently caused by three factors. First, the contracting practice in the industry resulted in oligopolistic behavior, because devices such as favored nation, periodic escalation, redetermination, and renegotiation clauses caused any price above in-line levels

since 1954 has imposed the duty of regulation upon the FPC.

From 1954 to 1960, the Commission attempted to discharge its new responsibility in the same way that it regulates pipelines, on a company-by-company basis, setting the rates of each producer according to his costs of service. This method, however, required the Commission to repeat lengthy hearing procedures for each independent operator in the nation. It consequently led to a breakdown in the administrative process,[11] a result that is easy to understand in view of the cumbersome nature even of the single consolidated cases with which we are faced here. The Commission gravitated toward lax approval of price increases. But in 1960, the

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to trigger other price rises. (These contract terms are defined in the Supreme Court's *Permian* opinion, 390 U.S. at 765, 88 S. Ct. at 1358, n. 46.) Second, the producers were able to assert market power even though the market for sales to large pipelines appears at first glance to be oligopolistic, because the pipelines typically needed large blocks of reserves at times not of their own choosing. Finally, the bargaining motivation of pipelines themselves was diluted because pipelines resold in a relatively inelastic market and hence could pass price increases on to consumers. The Commission chose to believe this evidence rather than to focus on concentration ratios, leadership turnovers, or conditions of entry, and it appears to have been justified in so doing. 4 Joint Appendix at 530d-34d (Commission's Opinion).

At the same time, there seems to be general agreement that the market is at least structurally competitive. The Supreme Court in *Permian* described producers as "intensively competitive." 390 U.S. at 757, 88 S. Ct. at 1354. See also P. McAvoy, *supra* note 9, at 7; E. Neuner, *supra* note 9, at 178-204, 280-281; M. Adelman, The Supply and Price of Natural Gas 39 (1962).

[11] *See* J. Landis, Report on Regulatory Agencies to the President-Elect 54 (printed for the use of the Senate Comm. on the Judiciary, 86th Cong., 2d Sess., 1960).

Supreme Court's *CATCO*[12] decision reversed an FPC certification order and directed the Commission to take steps to keep prices "in line." The Commission temporarily responded to this mandate by the "in-line" pricing policy, which stated that the Commission would not approve new certificates providing for gas sales at prices higher than the prevailing rate in the area, and by the "guideline" doctrine, which gave notice that the Commission would not give advance approval to price increases above certain area maxima.[13] Price increases above these guidelines thus subjected the producers to the possibility of refund obligations.

Also in 1960, the Commission began work on a more thorough solution to the problem with the first area rate proceeding, which covered the Permian Basin area of New Mexico and the Texas Panhandle. In subsequent years, the Commission simultaneously had examiners hold hearings on four other areas, of which the area involved in the instant case was one.

A. *The Permian Basin Area Rate Cases*

In *Permian*,[14] the first area rate case, the FPC set

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[12] *Atlantic Ref'g Co. v. FPC*, 1959, 360 U.S. 378, 79 S. Ct. 1246, 3 L.Ed.2d 1312 (known as the *CATCO* case). The Court urged the Commission to disallow or condition new certifications "where the proposed price is not in keeping with the public interest because it is out of line or ... might result in a triggering of general price rises or an increase in the applicant's existing rates ...."

[13] These matters were set out in the FPC's *Statement of General Policy* No. 61-1, 1960, 24 F.P.C. 818.

[14] *Permian Basin Area Rate Proceeding*, 1965, 34 F.P.C. 159, *affirmed in part and reversed in part sub. nom. Skelly Oil Co. v. FPC*, 10th Cir. 1967, 375 F.2d 6, *affirmed in full, in re Permian Basin Area Rate Cases*, 1968, 390 U.S. 747, 88 S. Ct. 1344, 20 L.Ed.2d 312.

maximum and minimum rates for an entire gas producing area on an industrywide basis. It did so by examining costs and setting a rate of return for the area's gas producing industry as a whole. It engaged in a degree of economic experimentation by creating a double-tiered pricing arrangement: The maximum price for "new" gas, gas not yet under contract of interstate sale by the cutoff date of January 1, 1961,[15] was set higher than that for "old" gas in order to stimulate exploration.[16] Old gas was priced on a cost-recovery basis on the theory that a price incentive would not encourage development of gas that had already been sold. Having set these maxima, the Commission froze them for two-and-one-half years by imposing a moratorium on price increases in excess of the ceilings as set. It stated that extraordinary circumstances would induce it to allow petitions for relief from the ceilings

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[15]This date was chosen for three reasons. First, it was the most convenient date following 1960, the year of most data for old gas. Secondly, the in-line and guideline policies had been established in 1960. Thirdly, this date reflected the Commission's estimate of the time at which the industry acquired the capability to drill "directionally," i.e., to explore specifically for gas rather than finding gas as a by-product of the search for oil. 34 F.P.C. at 189. This directionality hypothesis is a major basis of area rate regulation as the Commission has implemented it, because multi-price regulation depends upon the function of greater prices to elicit gas exploration. The hypothesis is not without its critics. *See Foster Associates Report*, December 18, 1969, at 9-10.

[16]The new gas ceiling was 16.5 cents per thousand cubic feet (Mcf) in Texas or 15.5 cents per Mcf in New Mexico, and the old gas ceiling was 14.5 cents per Mcf in Texas or 13.5 cents per Mcf in New Mexico. The difference reflected the fact that the Texas price included state taxes while the New Mexico price did not. Casinghead gas was priced at old gas ceilings irrespective of its vintage. The Commission also set a minimum price of 9 cents per Mcf.

but made it clear that the moratorium would not be lightly disregarded.

The Commission's decision was appealed to the Tenth Circuit. That court sustained the Commission's power to regulate producers by setting industrywide rates and imposing moratoriums on increases, but remanded the case to the Commission because it found that the Commission had failed to include required findings as to the consequences of its order on the gas industry or to specify with sufficient exactness the circumstances under which special relief from maximum rates would be granted. The Tenth Circuit's decision, in turn, was reviewed by the Supreme Court, which reversed the Circuit and affirmed the Commission in full. The Supreme Court's *Permian* opinion is thus the star by which we must do most of our steering in this case.

In *Permian*, the Supreme Court made several different types of determinations. First, it concluded that the Commission had the authority, under the Constitution and Natural Gas Act, to set industrywide rates and to impose ancillary regulations, such as moratoriums, necessary to make area proceedings work. Secondly, it sustained the Commission's use of the cost method for pricing, its determination of rate of return, and its double rate structure; or, in other words, it approved the components of the rates as set. Thirdly, it approved the overall effect of the rates, holding that Commission findings supported by substantial evidence indicated that the rates would produce adequate aggregate revenue, would generate sufficient growth, and would not create unjust results on individual producers. This approval of "overall effect" findings reflects a

somewhat charitable interpretation of the Commission's work,[17] one that the Court emphasized was warranted because the Commission was at an experimental stage in a new and difficult undertaking. At the same time, the Court apparently agreed with the Tenth Circuit that the paucity of findings as to the consequences of the order was a major deficiency, because it stated that it expected the Commission to do better in future proceedings.

The *Permian* decision thus indicates that a reviewing court must look to both individual components and overall effect of rates set by the Commission, but that the Commission has broad discretion that is not to be ineffectuated by either theoretical disagreement with its methods or by discovery of inadequacies that are caused mainly by the difficulty of the regulatory undertaking. The Commission is to be affirmed if it has followed the correct legal standards and acted on the basis of substantial evidence, and under any fair interpretation of *Permian* it appears that the legal standards themselves are to be construed liberally when applied to a regulatory effort still in the experimental stage. This "experiment" doctrine, together with the substantial evidence rule, is background for our consideration of most of the issues presented on this appeal.

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[17]The Commission made no assessment of the effect of its prices on supply, demand, reserves, or industry structure. The Supreme Court advised that in future cases the Commission should state more "fully and carefully ... its assessment of the consequences of its orders for the character and future development of the industry." 390 U.S. at 792, 88 S. Ct. at 1373.

B. *The Southern Louisiana Area Rate Cases*

All parties are in agreement that Southern Louisiana is the most important gas-producing area in the country. The FPC has defined this area to include all parts of the state south of the thirty-first parallel, together with all offshore territory[18] in the federal domain that would be bounded by the Louisiana borders extended into the Gulf. At present, Southern Louisiana accounts for approximately one-third of the nation's gas production, and its untapped, unproven reserves, particularly those in the offshore portion, are among the nation's most promising. Natural gas, in turn, is the nation's most important, or at least most widely used, source of energy.[19]

Proceedings to set rates for this area began in 1961, nearly a decade ago. The initial hearing ended in 1965 and the examiner rendered his decision in 1966, after the Commission had written its *Permian* opinion. The Commission rendered its final decision in 1968, a few months after the Supreme Court had decided *Permian*. The decision was modified in some respects by a new opinion on rehearing in early 1969.

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[18] "Offshore" gas production, in this opinion, means production outside state boundaries and thus not subject to state severance taxes, i.e., that in the federal domain.

[19] In 1965, the year the record in this case closed, Bureau of Mines figures attributed 35.7 percent of this nation's total energy production to natural gas. The percentage has been steadily increasing over the years. For 1968, the producers quote a figure of 37.5 percent. Brief for Amerada Group at Appendix B-2.

(1) The Rate Structure

The Commission repeated in Southern Louisiana the multiple rate structure it had introduced in *Permian*, this time setting three different price levels for what it denominated as first, second, and third vintage gas. For first vintage gas, that for which contracts of interstate sale had been made prior to 1961, the Commission set a ceiling of 18.5 cents per thousand cubic feet (Mcf). For second vintage gas, that contracted for between the dates of January 1, 1961, and October 1, 1968,[20] it set a ceiling of 19.5 cents. For third vintage gas, that contracted for after October 1, 1968, it set a ceiling of 20 cents. For offshore gas in the federal domain, which is not subject to the Louisiana severance tax, it set prices for each of the three vintages 1.5 cents below onshore levels. For casinghead gas (gas produced in association with oil), the Commission set prices equal to those of first vintage gas irrespective of the vintage. The Commission found that casinghead gas is discovered largely as a product of the search for oil and exploration for it thus could not be encouraged by the higher prices of second and third vintage gas.

The price structure thus established is summarized in the following chart:

Vintage or Type	*Onshore Price*	*Offshore Price*
First vintage	18.5 cents	17.0 cents
Second vintage	19.5 cents	18.0 cents
Third vintage	20.0 cents	18.5 cents
Casinghead	18.5 cents	17.0 cents

[20] The reasons for the establishment of the January 1, 1961 date were similar to those for its establishment in Permian. *See* note 15 *supra*. The October 1, 1968 date marked the approximate end of these proceedings before the Commission.

The prices for new, nonassociated gas are higher than those for all other vintages and well types, because the Commission determined, as it has in *Permian*, that price should be used to elicit the appropriate level of future exploration and development. In order to enforce these ceilings for gas of first and second vintages that had already been produced and consumed, the Commission ordered substantial refunds of moneys collected in excess of its maximum rates.[21]

(2) The Commission's Cost Determinations

Although the rate structure contains some noncost elements, it is closely tied to cost computations.[22] The Commission used two different methods of computing costs, one of which it applied to old gas (first and second vintage) and the other to new gas (third vintage). New gas is priced to allow for the appropriate level of exploration, and the Commission determined that exploration for gas was and should be undertaken on a nationwide basis, so new gas costs are based upon present costs for the entire nation. Old gas is priced so as to allow recovery of costs actually incurred in its production, and therefore the costs used are historical area costs, i.e., those of the Southern Louisiana area itself during the periods covered by the earlier vintages.

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[21]The Commission ruled that, by further order, it would require refunds of the difference between the amounts collected and amounts that could have been received under the applicable area rate (or the amounts that would have been received under firm certificates or settlement rates if those rates were higher than the area rate).

[22]The Commission relied upon published data, testimony, and questionnaires filled out by producers to collect its raw cost data.

The bulk of the Commission's opinion is devoted to computation and explanation of costs. Included in its total is an allowance for a rate of return of 12 percent, which is the same rate that was set and approved in *Permian*. We have set out the other elements of the Commission's cost findings in tabular form in the footnote below.[23]

(3) Moratoriums on Increases in Excess of Maximum Rates

In establishing rate ceiling freezes, the Commission went substantially farther than it had hazarded in its earlier *Permian* decision. It imposed a moratorium of a little more than five years — lasting until January 1, 1974 — on rate increases for third vintage gas in excess of the maximum prices it set. For first and second vintages, the moratoriums were to last indefinitely. These moratoriums mean that the vintage ceilings are to remain in effect throughout their duration, and that

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[23] All figures given are unit costs, in cents per Mcf. The grouping of flowing gas costs is different from that for new gas; the flowing gas E&D computation, for example, contains some

Item	*New Gas*	*Flowing Gas*
Exploration and Development	4.14	4.17
Production Operating Expense	2.70	1.93
Liquid Credit	(3.30)	——
Depletion, Depreciation, Amortization	4.04	3.19
Return on Investment	5.33	5.17
Return on Working Capital	0.35	——
Regulatory Expense	0.15	0.17
Royalty	2.24	——
Area Gathering	0.51	0.51
Production Tax	2.30	2.30
TOTAL	18.80	18.36

producers cannot collect prices in excess of maximum rates even subject to refund.

However, the Commission provided, as it had in *Permian*, that it would always be open to a petition to lift moratoriums for individual producers or to modify area rates as a whole in the event that changed circumstances made either of these steps advisable. Moreover, it quoted language of the Supreme Court stating that it would be "desirable" if the Commission specified more precisely the conditions for relief and, in response to this language, gave examples of changes that would cause it to lift moratoriums or change rates.[24]

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[24] Area rates "will be modified if a showing is made that unit costs — reflecting amounts spent and reserves found — have increased to such an extent that an increase in area rates is required." As to individual producers, the Commission recognized that it was avoiding "precise specification of circumstances that would justify special relief," but stated that:

> "However, certain principles have been established. Overall high cost of service of an individual producer is not a ground for relief. The fact that current revenue from a particular well is less than the costs of continuing its production is a ground for relief. The fact that a producer can obtain a higher price elsewhere is not a ground for relief. Certain producers have already requested price relief, contending that unusually high pressure, great volume, concentrated delivery points, delivery of large quantities at one point, unusually high gas quality, unusually good deliverability and the availability of gas for swing purposes justify an increased price. We have determined that none of these, nor all of them together, are grounds for price relief."

These and other statements of the Commission, taken together, probably constitute as specific an exposition of circumstances for relief as can be expected at this stage in area regulation.

In addition to setting maximum rates, ordering refunds, and imposing moratoriums, the Commission took action along a number of other lines that are of lesser significance in this case.[25]

(4) Commencement of New Proceedings for this Area

On December 15, 1969, shortly before oral argument in the instant case was heard, the Commission instituted new proceedings to reconsider all major actions it had taken in the orders before us. In other words, the Commission is now holding hearings that will probably result in substantial modifications of the rates set in this case. In its order initiating the proceedings, the Commission advised the parties that it would receive evidence concerning "the adequacy of gas supply and adequacy of service to consumers, the demand for gas, the cause of a gas shortage, if any, the effect of price on gas supply and demand, and other relevant economic evidence, together with data as to the current, nationwide cost of finding and producing nonassociated gas."[26] Similar considerations

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[25] The Commission established a system of quality discounts that were to be used in adjusting maximum rates, outlawed certain types of flexible pricing clauses resulting in increases over ceilings, created special exempt types of producer sales, exempted "small" producers from certain requirements, and determined that minimum rates need not be established.

[26] *Order Enlarging Investigation and Proposed Rulemaking*, 1969, ____ F.P.C. ____ [No. AR69-1; slip opinion dated December 15, 1969, at 3]. The Commission indicated that "we desire to have this proceeding expedited in every way possible." Prehearing was set for January 27, 1970.

The Commission had already set part of the offshore territory for reconsideration in its opinion on rehearing. The Order

are to be taken up with respect to old gas, and the moratoriums are to be re-examined.

Since the new proceeding may affect rates for all vintages, and since the data the Commission has called for reflects the possibility of a radical change in approach, this Court was naturally concerned about the effect of the new proceeding upon our disposition of the instant appeal. At oral argument, however, all parties agreed that the proceeding should have no effect upon our review, and we now agree.[27] Above all, we do not view the new proceeding as a "confession of error" by the Commission as the producers have invited us to do. It is true that the Commission now recognizes the possibility of a serious supply deficiency and that it did not recognize this possibility in the decision we are reviewing.[28] This awareness, however, and the Commission's prompt action upon it, militate in favor of affirmance rather than reversal. The new proceeding is evidence of the Commission's ability to adapt the regulatory process to changing circumstances. We conclude that the indications that there is a supply deficiency should be examined in this second-round proceeding before the Commission. The

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of December 15 enlarged that proceeding to include the entire area.

[27] The maximum rates that the Commission has set, in addition to the moratoria, are to remain in effect throughout the new proceeding, which may last for years. Moreover, it was never contemplated that there should be a single area proceeding setting rates once and for all; rather the Commission has always made it clear that it intended to review the rates it had set whenever the circumstances made it advisable to do so. *See* note 24 *supra*.

[28] *See* section III D *infra*.

evidence that there is a deficiency seems very strong, but given the Commission's actions we are convinced that it can now deal with the problem as effectively as present circumstances will allow.

At this point, we proceed into analysis of the specific arguments made by the consumer interests on the one hand and by the producers on the other.

II. THE CONSUMER ARGUMENTS

There are three main arguments advanced by the intervening parties on this appeal. First, these parties contend that the Commission overstated certain of its calculated costs. Second, they argue that the record does not furnish substantial evidence to justify a rate of return as high as 12 percent. Thirdly, they argue that the Commission committed reversible error in adding noncost factors to a rate based upon the costs (including return) it had computed. We take up the consumer issues in this order.

A. *The Commission's Cost Determination*

The consumer interests contend that the Commission overstated production operating expense for old gas by excluding casinghead gas, which is cheaper to produce, from consideration.[29] They also attack the

[29] About fourteen percent of gas produced in Southern Louisiana is casinghead, and the Commission states that "we are well aware that its indicated cost is substantially below that of gas-well gas." The ADG has calculated the difference in cost at about 3 cents. Assuming this figure to be correct (which we cannot really assume because joint costing of oil and gas is

Commission's allocation of exploration and development costs between oil and casinghead gas where oil and gas are discovered together.[30] They attack the

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judgmental), the inclusion of casinghead gas into the computation of costs for the first vintage would result in a total decrease in first-vintage price from 18.5 cents to approximately 18.3 cents by our calculation, or a difference of just over one percent. Especially in view of the cost-computation structure as a whole, which has frequently involved the Commission in the approximations of interpreting joint costs, we consider this amount de minimis, even conceding its accuracy. But our rejection of this argument is based upon more fundamental considerations. The assignment of costs to products jointly produced, as are oil and casinghead gas, is not an exact undertaking, and we think the Commission has acted on the basis of substantial evidence, particularly since it has set a rate structure under which casinghead gas of all vintages is assigned the lowest price, that of first vintage. The Supreme Court approved a similar calculation in *Permian*. *Cf.* ICC, Bureau of Accounts, Statement No. 4-54, Explanation of Rail Cost Finding Procedures and Principles Relating to the Use of Costs, Ch. 1, pt. 4 (1954).

[30] It seems clear that oil, which is more valuable than a volume of gas of the same heat content, should bear more of the exploration and development cost. The Commission, as its first step in assigning these costs, determined a unit by which gas and oil could be compared: the amount of each that is required to produce a Btu of heat. It then determined what it called the "economic factor," which is the number of gas units that equaled in value a unit of oil. By strict computation, the Commission arrived at an economic factor of 4.0. This factor would have indicated the assignment of four times as much of the cost to oil as to gas. It then adjusted this factor to 3.5, however, to allow for the fact that revenues from flowing gas should be expensed against *present* drilling, which is undergoing a continuing shift away from searches directed solely at discovering oil toward searches directed at finding gas. We think it is reasonable for current revenues from flowing gas to be compared with current expenses in exploration for new gas. Thus the Commission adopted an allocation that assigned higher costs to exploration for gas than would its straight calculation, but it justified this modification by a qualitative finding that is based upon substantial evidence.

allowance for "plant gathering," or short-distance pipelining from wellhead to the producer's plant for the purpose of extracting salable liquids.[31] Finally, they contend that the Commission understated the credit for salable liquids extracted from the gas stream, which is subtracted from gas production costs.[32] We consider each of these matters in footnotes appended hereto.

On the whole, we find each of these cost criticisms defective for one or both of two reasons. First, they deal mainly with amounts that are small compared to the accuracy that can be expected of computations of

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[31] The consumer interests argue that these plant gathering costs should rather be assigned to those salable liquids, since they are incurred in producing them. On rehearing, the Commission indicated that the allowance might have been overstated slightly, but that ". . . the entire allowance is only 0.33 cents. The amount of possible excesses does not seem worth the burden of further hearings on other allocation methods." The Commission indicated that a significant portion of the 0.33 cents is chargeable against gas because part of the liquid revenues do not go to the producers at all but rather are paid to the leasehold, reducing its cost. Another significant part is also chargeable to gas, because transportation to a plant is usually done in furtherance not only of liquid extraction but also of moving the gas stream itself closer to the centralized point at which it must be delivered. Therefore, we agree with the Commission that possible excesses in the 0.33 cent figure, which is itself less than 2 percent of the total price, would be de minimis, and we hold that the plant gathering allowance is based upon substantial evidence.

[32] They argue that the credit of 3.5 cents for lease-extracted liquids and that of 0.50 cents for plant-extracted liquids is too low. The Commission calculated the lease liquid credit at 4.18 cents, but it reduced this figure to allow for a trend of decreasing revenues from these liquids. It reduced the plant liquids credit from a calculated 0.75 cent to 0.50 cent to allow for a duplication of credits elsewhere. These actions are supported by substantial evidence.

this nature.[33] Secondly, and more importantly, they place too much emphasis upon abstract manipulation of figures. There is nothing in the substantial evidence rule that prevents the Commission from performing calculations based upon necessarily imperfect assumptions when it explains the reasons for those assumptions. Likewise, there is nothing to prevent it from re-examining and adjusting the result of a calculation based upon imperfect premises, provided it justifies its actions on the basis of the record.[34]

B. *The Rate of Return*

Next, the consumer interests argue that the Commission acted arbitrarily, discriminatorily, or without substantial evidence in establishing a rate of return as high as 12 percent. The argument appears to be based upon the fact that the "special circumstances"

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[33]A generous reduction for all four cost criticisms considered here, if *all* of them were accepted, would certainly not exceed 1.5 cents. Commissioner Carver, on the other hand, indicates reasonable changes that could result in an *increase* of 4.0 cents, if all were adopted, in his dissent to the opinion on rehearing. *See* note 85 *infra*. The inherent, unavoidably approximate nature of rate regulation under legislative standards has been noted by both economists and courts, including the Supreme Court in *Permian*, 390 U.S. at 790, 88 S. Ct. at 1372 n. 59; *see also* J. Bonbright, Principles of Public Utility Rates 27, 67 (1960). Of course, the inaccuracy of pricing techniques is one reason why the FPC is required separately to determine the consequences of its pricing actions. *See* section III (D) *infra*.

[34]Provided it meets other requirements of law, the Commission may employ any "formula or combination of formulas" it finds appropriate. It may "make the pragmatic adjustments which may be called for by the circumstances." *FPC v. Natural Gas Pipeline Co.*, 1942, 315 U.S. 575, 586, 62 S. Ct. 736, 743, 86 L.Ed. 1037; *see also Permian*, 390 U.S. at 800, 88 S. Ct. at 1377.

cited in *Permian* as justification for the 12 percent rate of return — namely, that the gas was frequently of inferior quality so that the return was likely to be lowered — are not present in Southern Louisiana, where nearly all of the gas is of high quality.[35] Alternatively, it is based upon the contention that the Commission did not comply with the "comparable earnings" test of *FPC v. Hope Natural Gas Co.*, 1944, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333.

We are not impressed with the argument that circumstances present in *Permian* are not present here, because even if, *arguendo*, we concede the relevance of this proposition, we find circumstances not present in *Permian* that are important here. The Southern Louisiana area is a crucially important gas-producing region in which new exploration needs especially to be encouraged. A great portion of the discoverable gas in the area is far offshore. The finding that new reserves of gas can be found without a significant rise in unit costs is premised in part upon the increasing use of new technology,[36] and the need to adapt produc-

[35] We recognize possible validity in the consumers' argument that Commission reliance on such matters as hurricanes in fixing a 12 percent rate of return for Southern Louisiana is misplaced. It might have been more appropriate to treat these matters as above-the-line costs (reflected, for example, in insurance premiums) rather than as a risk upon which one obtains return. *Permian*, however, indicates that arguments of this type should be addressed to the discretion of the Commission. 390 U.S. at 811, 88 S. Ct. at 1383. Furthermore, we do not need to rely heavily upon these factors, because the Commission has advanced other justifications for the rate of return.

[36] *See* 3 Joint Appendix, pt. 1, at 239d (Initial Decision). The Commission relied heavily upon the examiner's findings in fixing the rate of return.

tion to a constantly changing technology involves risks that definitely justify a high rate of return even for an industry taken as a whole.[37] Furthermore, the possibility of a supply deficiency, a possibility that has become stronger during the pendency of this review, strengthens our conviction that substantial evidence supports a return as high as 12 percent.

Nor do we find any merit to the argument that the Commission failed to apply the comparable earnings test correctly.[38] In discussing the required rate of return, the parties varied in their recommendations from 9-9.5 percent (presented by consumer interests) to 20-24 percent (presented by the Hunt Oil group of producers).[39] The Commission considered all evidence,

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[37] *See* G. Stigler, Capital and Rates of Return in Manufacturing Industries 90-91 (1963); *cf.* J. Galbraith, The New Industrial State (1967).

[38] We note at the outset that the Commission is not required to compute rate of return on the basis of the comparable earnings test. The Permian decision states that "other tests might properly have been employed." (The Court cites with apparent approval the examiner's discussion of rate of return in this very case, the Southern Louisiana proceeding). 390 U.S. at 805, 88 S. Ct. at 1380 & n. 1; *see also* J. Bonbright, *supra*, note 33, at 240-83. However, we review the Commission's decision under the comparable earnings test because that is the standard it evidently followed.

The test has been formulated as follows: Return should be "equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties." *Bluefield Water Works & Improvement Co. v. PSC*, 1923, 262 U.S. 679, 692, 43 S. Ct. 675, 679, 67 L.Ed. 1176; *FPC v. Hope Natural Gas Co.*, 320 U.S. at 603, 64 S. Ct. at 288.

[39] The Amerada group of producers argued for a 16-18 percent rate of return. The FPC Staff recommended 9.5 percent and asserted that 12 percent "can well be considered as in excess

then made its determination by abstracting the rate of return earned by a group of unintegrated gas producers over the years 1958 to 1962.[40] It adjusted this figure slightly, in ways that it thought appropriate, to allow for possible inadequacies in its data base.[41] The Commission chose unintegrated gas producers because it quite reasonably decided that these companies would be most representative of the risks the industry was facing, and it chose the period 1958 to 1962 because that was the most recent for which the record furnished reliable data. In light of the standard of review, which is whether the Commission's findings are supported by substantial evidence, we are particularly unimpressed with the argument of one intervening party that the FPC "erroneously failed to consider relevant evidence." There is substantial evidence to support a rate of return as high as 12 percent, and the Commission properly applied the test expressed in *Hope*.[42]

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of the upper limit of the range of reasonableness." *See* 3 Joint Appendix, pt. 1, at 164d, 173d, 185d, n. 1. (Initial Decision).

[40] *See* 4 Joint Appendix, pt. 1, at 567d-74d (Commission's Opinion).

[41] "[W]e recognize that the limited available data on non-integrated companies refers to a few unusually successful producers. Also, earnings-book ratios of integrated companies deserve to be given some weight." *Id.* at 573d.

[42] The comparable earnings standard is a general one, encompassing several indicia of earnings and requiring both ability to attract capital and a fair return on equity. *Williams v. Washington Metropolitan Area Transit Comm.*, D. C. Cir. 1968, 415 F.2d 922, 933. Certain types of computation are unacceptable, *see Id* at 970 & n. 294, but the Commission has broad power to select the evidence upon which it should rely. We find that the Commission was obviously attempting to apply the comparable earnings test. The sole questions it struggled with were what companies' risks were comparable and what the earnings of those companies were. Its choice of evidence is reviewable under the substantial evidence standard.

C. *Noncost Elements in the Computed Prices*

As was previously mentioned, the Commission added small noncost elements to several of its maximum rates. It increased the second vintage ceiling by 0.7 cent over cost, the third vintage ceiling by 1.2 cents, and the ceiling on all offshore gas by an additional 0.8 cent.[43] The consumer interests attack these increments vigorously, describing them as "cushions," "bonuses," "lagniappes," and other labels implying that the producers are the object of open, unvarnished FPC generosity. They cite authority purportedly to the effect that a public utility cannot add noncost elements to a cost-based rate, relying heavily upon the recent *en banc* decision of the Court of Appeals for the District of Columbia Circuit in *Williams v. Washington Metro-*

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[43] We are singularly unimpressed with the characterization of this offshore factor as a "phantom tax" by both the MDG and the New York Commission. These parties begin by stating that the computed cost difference between offshore and onshore is 2.3 cents (the amount of the Louisiana severance tax), go on to show that the Commission's ceiling for offshore is only 1.5 cents, and from this conclude that the Commission has allowed 0.8 cent for "phantom" taxes inapplicable to offshore, which is outside Louisiana's taxing jurisdiction. The conclusion is the baldest of sophistry, for the 0.8 cent allowance has nothing to do with the Louisiana tax. It is a noncost element intentionally added by the Commission, and we consider it as such.

It is only fair to add, however, that this sophistry was made possible, if not plausible, by the Commission's failure to label noncost factors specifically and to justify them in a way clearly independent of costs. It is also a product of conflicting implications in the Commission's findings. *See* sections IV A (1), (4) *infra*. The raising of phantom issues such as this one wastefully consumes the efforts of a reviewing court.

politan Area Transit Commission, D.C. Cir. 1968, 415 F.2d 922.[44]

The *Williams* case is part of a heavy volume of litigation concerning regulation of mass transit in the District of Columbia. The excellent opinion of the court of appeals deals with a number of issues that are remanded to the Transit Commission. The issue that relates to our case concerns a "cushion" in the computed rate of return, constituting the amount the Transit Commission thought was "required to enable [the D.C. Transit System, Inc.] to maintain a sufficient surplus to cover contingencies and to assure the financial stability of Transit."[45] The court concluded that a fair and reasonable rate of return would itself include

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[44]The main thrust of the MDG argument is that the Commission failed to include adequate justification for the noncost factors in its opinion, an argument with which we would be inclined to agree were it not for the newness of area regulation. *See Colorado-Wyoming Gas Co. v. FPC*, 1945, 324 U. S. 626, 65 S. Ct. 850, 89 L.Ed. 1235; *United States v. Carolina Carriers Corp.*, 1940, 31 U.S. 475, 62 S. Ct. 722, 86 L. Ed. 971. This is a procedural issue crucial to appellate review. *See* notes 110-11 *infra* and accompanying text.

[45]All other issues remanded to the Transit Commission were so treated because of a lack of required findings, but the court disapproved completely the cushion in the rate of return. The Transit Commission had included the amount because of the possibility that its "conservative" cost and revenue findings might be inaccurate. It expressed a preference for adding a cushion above costs to cover this possibility rather than allowing for it in its cost findings because adjustment in cost findings would be compounded by the addition of return. The court did not dispute this proposition, which indeed is indisputable, but stated that "[n]otwithstanding the uncertainty that attends all prophesy, a regulatory agency is bound to make its forecasts as accurate as it possibly can, and a reviewing court is entitled to assume that it has done so."

assurance of financial stability and that under the circumstances the return added to costs was all that the Transit Commission should have allowed.

Even if we were to construe this case as broadly disapproving noncost elements, the application to the sprawling, wildcatting gas producing industry of principles developed in regulating bus and telephone companies would require major adjustments.[46] But this is not the extent of our disagreement with the argument advanced by these intervening parties. We do not understand the law of industry regulation, including the Williams case,[47] to prohibit noncost elements that are

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[46]The gas industry is different from metropolitan transit in that it requires a constant infusion of entrepreneurship of the highest order if even basic public needs are to be satisfied. The D.C. Transit System will continue to operate even if the return its investors expect in a given year is poor, because it is a true public utility subject to the orders of the Transit Commission. Its service may not be of the best quality if rates are too low, or, more importantly, its owners may have a Constitutional claim against the Government, but the public will not be irreparably injured. On the other hand, we count upon persons who carefully weigh investment risks for our supply of natural gas. We think the Commission here, having calculated the dangers involved in allowing the gas supply to lapse, and the probabilities that its estimates might be too low, is justified in having added the small noncost factors it thought were necessary. It found that it needed to do so to protect the public interest and not to assure any rights of gas producers. However, as the *Williams* case indicates, the use of noncost factors to allow for possible inaccuracies is not favored. Inaccuracy, if that is *really* the concern (and not higher costs), can result in a windfall to producers as easily as in a loss. *See* note 47 *infra*. We approve the use of noncost factors for this purpose under the facts of this case only.

[47]*Williams* is distinguishable from our case in several respects; it is so clearly so, in fact, that we feel justified in concluding that it is based not on disapproval of noncost increments but

based upon appropriate grounds. In *Permian*, the Supreme Court unequivocally stated that the FPC is not bound by the sum of cost and return even if it adopts costs as the primary basis of its calculations.[48] The most persuasive reason for this rule is that cost pricing is circular. Past production has taken place at a given level; if a regulatory body fixes prospective prices at the cost of that production, it may be freezing the level of production, too.[49] We think that the need for dramatically increased production from Southern Louisiana justifies the noncost factors added here, and that the FPC has power to include noncost elements that reflect its assessment of the need to use price as a tool to influence such economic relations. These are propositions that apply generally to regulation of utilities and quasi-utilities.

The Commission explained the reasons for its noncost additions as follows. The 0.8 cent cushion added to offshore gas prices was a reflection of the growing importance that offshore will have to assume if future development of reserves is to meet demand and also

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upon disapproval of egregiously inattentive regulation. The cushion had been added ostensibly to allow for inaccuracies in cost computations, but the court found that as the computations had been made any inaccuracies would lie on the side of generosity to the Transit Company. Moreover, in earlier years regulation by the Transit Commission had allowed, in reality, a return of equity of 21 percent for the Company, as versus a "comparable earnings" return computed at 7.5-8.7 percent. The Transit Commission had made no findings as to comparable earnings. 415 F.2d at 936-37, 973-74.

[48] 390 U.S. at 815, 88 S. Ct. at 1385 & nn. 97-99

[49] This argument is widely accepted; indeed, it was cited with approval in *Permian*. *See Id.* at n. 99 and authorities therein cited.

of the unavoidable uncertainty of cost data concerning offshore, since offshore drilling in deep water is a relatively new undertaking.[50] The noncost increments on second and third vintage gas prices were cushions against the possible adverse effects of cost changes or inaccuracies during a lengthy price ceiling freeze.[51] The Commission found that price stability over a longer period of time would be more in the public interest than a rate that was lower by a few percentage points, and we conclude that the length of these proceedings by itself furnishes substantial evidence to support this finding. We have no hestitation, moreover, in holding that this purpose is an appropriate one for inclusion of noncost elements in a cost-based price.[52] However, the Commission's fulfillment of its procedural duty of making findings leaves much to be desired.[53] In view of the Commission's failure to relate

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[50]These considerations are in apparent conflict with the Commission's finding that "it has not been demonstrated that the unit cost of gas is greater offshore than onshore." 4 Joint Appendix, pt. 1, at 622d. The Commission could have reconciled this conflict by indicating, for example, that it had *some* reason for thinking costs might be higher, or that the newness of the undertaking and the consequent unavailability of cost data was itself a risk justifying a higher return.

[51]This finding should have been discussed in light of the Commission's finding that costs were unlikely to rise. Evidently the Commission recognized some probability that costs would rise slightly, and the amount of the cushion is tied to this probability — but the Commission has not exposed its reasoning.

[52]*Cf.* 390 U.S. at 815, 88 S. Ct. 1385, n. 98.

[53]The Supreme Court affirmed in *Permian,* however, while being forced to read the Commission's mind even more than we are. The Commission there had said that "no [noncost] adjustments are required in the Permian Basin." 34 F.P.C. at 207. But the Supreme Court found that the Commission had actually used four separate types of noncost factors and had justified each. 390 U.S. at 815, 88 S. Ct. at 1385 n. 98.

its noncost additions to specific probabilities concerning influences upon supply or to make any showing as to the demand they are needed to meet,[54] we are hesitant to sustain the use of these increments and do so only because the Commission is still in the experimental stages of area regulation. We shall have more to say about these deficiencies below. At this point, we emphasize the fact that the Commission has justified the noncost factors by reference to considerations that ostensibly affect not private but broad public interests.[55]

We conclude that the arguments advanced by these intervening parties are without merit.

III. THE PRODUCER ARGUMENTS

The producers present the following four major arguments to this Court: First, that the moratoriums are unlawful; secondly, that the Commission failed to follow the comparable earnings test in assessing a

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[54]Noncost factors will often in the ultimate analysis relate to these market variables, although there are other possible justifications for them. Where noncost elements are used to relate supply and demand, the level of each and the relationship between them must be explored. Here, adequate supply, even though the Commission has not examined it, is obviously a major consideration lurking behind the noncost additions, expressed in the Commission's frequent allusions to the "importance" of the Southern Louisiana area. A finding as to "importance," without any identification of or discussion of the specific characteristic of the region that is important, is of little benefit to a reviewing court.

[55]*See* note 46 *supra; cf.* note 47 *supra.*

rate of return as low as 12 percent; thirdly, that the Commission's cost determinations are unlawful or erroneous; and finally, that the Commission failed to make the findings necessary to relate supply, demand and price according to the "end result" *test of the Hope* and *Permian* cases. We take up the issues in this order, with particular emphasis on the supply problem presented in the last argument.

A. *The Moratorium Provisions*

The producers' attack on the moratoriums is based upon the fifth amendment to the Constitution, the Natural Gas Act, the Administrative Procedure Act, and factual issues pertaining to the case. In *Permian*, as we have noted, the Supreme Court affirmed the Commission's imposition of a two-and-one-half year moratorium on rate filings in excess of ceilings. However, it did so only for the limited circumstances before it, and left the question of longer moratorium legality almost completely open:

> We cannot, given the apparent stability of production costs, the Commission's relative inexperience with area regulation, and the administrative burdens of concurrent area proceedings, hold that this arrangement was impermissible. We need not attempt to prescribe the limitations of the Commission's authority under §§ 5 and 16 to impose moratoria upon § 4(d) filings; in particular, we intimate no views on the propriety of moratoria created

> in circumstances of changing costs. These and other difficult issues may more properly await both clarification of the Commission's intentions and the necessities of the particular circumstances. *We hold only that this relatively brief moratorium did not, in the circumstances here presented, exceed or abuse the Commission's authority.*[56]

Considering this language, we think it incumbent upon this Court to meet the producers' arguments against these lengthier moratoriums as undecided questions.

At the outset, we find little merit to the producers' Constitutional complaints. The possibility that they may be deprived of property without due process of law is speculative and remote, and if such a deprivation occurs both courts and Commission will stand ready to remedy it. For the present, we find no such deprivation. Economic regulation under the commerce power, affecting an industry generally, is not a taking of property if the value of property is thereby reduced or business risks increased.[57] The producers have a

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[56] 390 U.S. at 782, 88 S. Ct. at 1367 (emphasis added).

[57] No constitutional objection arises from the imposition of maximum prices merely because "high cost operators may be more seriously affected * * * than others," *Bowles v. Willingham, supra*, 321 U. S. at 518, 64 S. Ct., at 649, or because the value of regulated property is reduced as a consequence of regulation. *FPC v. Hope Natural Gas Co., supra*, 320 U. S. at 601, 64 St. Ct. at 281; Permian, 390 U.S. at 769, 88 S. Ct. at 1361. *See also West Coast Hotel Co. v. Parrish*, 1937, 300 U.S. 3791, 57 S. Ct. 478, 81 L. Ed. 703; *Nebbia v. New York*, 1934, 291 U.S. 502, 54 S. Ct. 505, 78 L. Ed: 940; *Munn v. Illinois*, 1877, 94 U.S. 113, 24 L. Ed. 77.

fifth amendment right not to be forced to sell or surrender their property without either due process or just compensation, but the Constitution gives them no right to raise prices irrespective of Commission approval in the absence of a deprivation of property.

Similarly, we find no merit to the producers' argument under the Administrative Procedure Act.[58]

The moratorium provisions were validly promulgated after adequate notice when the rate proceeding began.[59] With these considerations disposed of, we turn to the more difficult questions presented under the Natural Gas Act.

The procedure contemplated by Section 4 of the Natural Gas Act[60] is designed to protect sellers from the

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[58] 5 U.S.C. § 550 *et seq.* (1967).

[59] The argument is based upon the following two contentions: first, that sections 7 and 8 of the APA, read in conjunction with section 4 of the Natural Gas Act, require rate orders to be made upon formal hearing and not upon the "informal" procedures established here, and second, that the issuance of the moratorium order was not preceded by the public notice required by section 4(b) and other sections of the APA. The answer to the first argument is that the instant proceeding is the rate order required to comply with sections 7 and 8; we do not think these sections apply to the decision whether to grant individual relief after the just and reasonable rates have been set. This is the clear import of the *Permian* approval of group regulation. *See* 390 U.S. at 744, 88 S.Ct. at 1364, distinguishing *Bowles v. Willingham*, *supra*. The second argument likewise has no merit. The Commission published notice regarding the commencement of area proceedings, and the notice in our view was sufficient to inform all parties that ancillary regulations would be considered. 26 Fed. Reg. 4296 (1960).

[60] 15 U.S.C. § 717c (1963).

possibility of property deprivation through confiscatory rates that might not be increased quickly enough under ordinary hearing procedures. Section 4 provides that "[u]nless the Commission otherwise orders," a natural gas company must file a notice of rate increase thirty days before the effective date if it increases its rate unilaterally. The Commission may suspend the rate increase for a period of no more than five months, during which time it must begin hearings to determine whether the increased rate is just and reasonable. If the hearings are not completed by the end of five months, the gas company may collect the increased rate subject to refund. Limited encroachments upon this procedure have been permitted the Commission when they were necessary to effectuation of other requirements of the Act, the most notable being the Supreme Court's approval of the *Permian* moratorium.[61]

In considering the legality of moratorium provisions generally, we begin with the proposition that under section 5(a)[62] of the Act the Commission may determine rates and prescribe the "rule, regulation, prac-

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[61] The Court in *Permian* also approved Commission orders of indefinite duration prohibiting increases above maximum rates brought about by flexible pricing clauses. 390 U.S. at 782-83, 88 S. Ct. at 1368-69. *See also Atlantic Ref'g Co. v. FPC*, 1959, 360 U.S. 378, 79 S. Ct. 1246, 3 L. Ed. 2d 1312 (approving prospective ceilings on price in section 7 proceedings); *cf. United Gas Improvement Co. v. Callery Properties, Inc.*, 1965, 382 U.S. 22, 86 S.Ct. 360, 15 L. Ed. 2d 284.

[62] 15 U.S.C. § 717d(1963). Moreover, section 16 of the Act, 15 U.S.C. § 717o (1963), gives the Commission power "to perform any and

tice, or contract to be thereafter observed." Thus section 4 does not give producers an "invincible right to raise prices subject only to a six-month delay and refund liability."[63] The section provides only that "a change *cannot* be made without the proper notice to the Commission; it does not say under what circumstances a change *can* be made."[64] Thus the Commission is not required to follow the procedure that section 4 contemplates for each individual producer. Moreover, once a just and reasonable rate has been established, the Commission has a responsibility to prevent rate increases in excess of that rate without changes in circumstances. The Supreme Court recognized this Commission responsibility with regard to gas producers in the *Phillips* and *CATCO* cases, and it recognized that the Natural Gas Act contemplates FPC power to carry out its purposes realistically.[65] If the Commission is to discharge its duty of regulating production, it must use the area rate ceiling method or some analogous industrywide approach. It cannot regulate individual producers simply because the strain that approach would put upon its time and resources would be prohibitive. And moratoriums are necessary if the area regulation method is to work at all. Uni-

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all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter."

[63] *United Gas Improvement Co. v. Callery Properties, Inc.*, 1965, 382 U.S. 223, 232, 86 S. Ct. 360, 365, 15 L.Ed. 284 (separate opinion of Mr. Justice Harlan).

[64] *United Gas Pipeline Co. v. Mobile Gas Service Corp.*, 1956, 350 U.S. 332, 339, 76 S.Ct. 373, 378, 100 L.Ed. 373.

[65] *See* notes 5-13 *supra* and accompanying text.

lateral producer price increases in excess of the ceilings would otherwise involve the Commission immediately in the task of determining whether each increased rate was just and reasonable in terms of the financial position of each individual producer, which is precisely the problem the Commission faced before area regulation and so badly needs to avoid.[66] By putting a ceiling on rates in such a manner that the ceiling is likely to cover the just and reasonable rate for a number of years, and imposing a moratorium that lasts no longer than the period that the ceilings are likely to be adequate the Commission can discharge its regulatory responsibilities with minimum encroachment on the salutary procedures contemplated by section 4.[67]

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[66] Certain of the producers urge that §§ 4 and 5 must in combination be understood to preclude moratoria upon filings under § 4(d). They assert that the period of effectiveness of a rate determination under § 5(a) is limited by § 4(e); they reason that § 4(d) creates an unrestricted right to file rate changes, and that such changes may, under § 4(e), be suspended for a period no longer than five months. If this construction were accepted, it would follow that area proceedings would terminate in rate limitations that could be disregarded by producers five months after their promulgation. The result, as the Commission observed, would be that "the conclusion of one area proceeding would only signal the beginning of the next, and just and reasonable rates for consumers would always be one area proceeding away." 34 F.P.C., at 228. 390 U.S. at 781, 88 S. Ct. a 1367. The same conditions, of course, are present here.

[67] It is to be emphasized that the moratorium provisions do not prohibit increased rate filings. They prohibit rate filings *in excess of the ceilings*. These ceilings are the maximum prices that the Commission feels can be considered just and reasonable. The Commission has added noncost increments to the rates that present the greatest danger of inadequacy, and it

It remains to consider whether the moratoriums actually imposed here are factually supportable — whether they are in fact reasonable and based upon substantial evidence. Our discussion above indicates that these factors should be examined in light of two considerations: First, whether the moratoriums as ordered are necessary to effective area regulation, and second, whether substantial evidence indicates that they are unlikely to result in inadequate ceilings later in their duration.[68] If moratoriums may be approved in principle, we have little difficulty in approving a moratorium of five years under the circumstances here. In *Permian*, the two-and-one-half year moratorium was exhausted before the Commission's order was finally affirmed by the Supreme Court.[69] To prescribe a moratorium of five years on a finding that stable prices for the area are desirable, we think, is within the discretion of the Commission, especially when the proceeding to establish those rates has been longer than five years and appellate review promises to lengthen the period substantially. A five-year mora-

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has provided avenues of extraordinary relief, both industry-wide and on an individual-producer basis, whereby the moratoriums may be lifted. We do not think that the moratorium provisions, which are necessary to the area regulation process, "write section 4 out of the Act," as the producers have contended.

[68]These two considerations can also be extracted from the following *Permian* language: "We cannot, given the apparent stability of production costs, the Commission's relative inexperience with area regulation, and the administrative burden of concurrent area proceedings, hold that this [moratorium] arrangement was impermissible." 390 U.S. at 781, 88 S. Ct. at 1367.

[69]Moreover, the Tenth Circuit had stayed the moratorium order and it consequently had no effect at all throughout its duration. 390 U.S. at 777, 88 S.Ct. at 1365.

torium in this case is also justified by the Commission's observance of recent trends and its conclusion that costs are remarkably stable or even slightly declining. This finding, together with the noncost factors, makes it reasonable to conclude that the rates will not in the future become unfairly low *provided* they are set at just and reasonable levels now. Of course, the practical effect of our approval of this moratorium is minimal, however, since the Commission is reviewing all moratoriums in the new proceedings, and supply problems, if they exist, will require quick remedies.

We have greater difficulty with the indefinite moratoriums imposed upon first-and-second-vintage prices. Our trouble is based not only upon the fear that these provisions could some day result in inadequate ceilings — even though the Commission has made findings based upon substantial evidence that cost increases in the *near* future are unlikely — but also upon our apprehension that they are in excess of what is reasonably necessary for area regulation to function. Consequently, although we have determined that the Commission should be affirmed in full, we limit our approval of the indefinite moratoriums to the circumstances present on this appeal. We stress the fact that the Commission is holding hearings now to determine whether the moratoriums should be modified, and that the result of this determination should be reviewed without reference to approval on this appeal.[70]

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[70] Specifically, considerations relating to the law of the case should be accorded only limited significance, since experience with area regulation may increase to such an extent as to constitute a change in circumstances.

We also emphasize that the experimental nature of producer regulation makes us as yet reluctant to reverse the Commission on a matter which has little present impact[71] and which can be corrected, if experience shows it erroneous, in the future. These considerations, together with the Commission's findings and its demonstrated willingness to use the avenues of relief it has provided, elicit our qualified affirmance of the moratorium provisions.

B. *The Rate of Return*

The producers attack the rate of return mainly on the ground that the Commission failed to follow properly the comparable earnings test expressed in *Bluefield Water Works & Improvements Corp. v. PSC*, 1923, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176, and *FPC v. Hope Natural Gas Co.*, 1944, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333.[71A] They particularly claim that the period chosen by the Commission was unrepresentative, and present persuasive evidence to that effect.[72]

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[71] Theoretically speaking, the indefinite nature of the moratorium will assert itself only in the future. Practically, it will have some effect on industry expectations and hence industry conduct. But since the new proceedings before the Commission create expectations that ceilings may be changed, we consider the present effect of the indefinite moratorium to be minimal.

[71A] We reiterate, as the producers seem to lose sight of the fact, that the Commission is not *required* to compute return by the comparable earnings test. *See* note 38 *supra*.

[72] The producers' most easily comprehended presentation is a graph over the years 1947 to 1968 of rates of return they considered comparable. The 1958-1962 period chosen by the Commission is decidedly a dip in the curve, reflecting a recession during these years. Also, the producers attack the Commission's choice of companies to compare and failure to consider evidence showing a rise in earnings since 1963. Persuasive evidence, however,

The trouble is that we have already determined, in our discussion of the consumer-interest contentions concerning this issue, that there is also persuasive evidence to support the Commission's findings and the Commission followed proper legal standards. Reliance upon returns earned by unintegrated producers during the latest period for which the Commission felt it had reliable data was appropriate, in light of the widely divergent evidence presented in this case. Producer contentions to the contrary amount to an attack on the Commission's choice as to which evidence to believe.

C. *The Commission's Cost Determinations*

Producer attacks on the cost computations are many and varied. Most are cognizable under the substantial evidence standard. At the outset, however, we are met with the contention that the very method of cost pricing is too imprecise to be used in regulating the gas-producing industry. We must reject this contention. In a situation wherein the Commission has found that market imperfections tend to force price to ex-

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supports the Commission's action, and we are not engaged in finding these facts anew.

Furthermore, the rate of return even as set may be higher than 12 percent. Noncost factors, if they are viewed as additions to the return — and this is a logical way to view them, since they must go either to pay costs or to increase return — would increase return to 14-16 percent for new gas. Earnings on equity at a 12 percent rate on capital, of course, are higher than 12 percent because they are leveraged by debt; here they amount to about 13.3 percent. Finally, the producers' argument for a 16-18 percent rate of return is defective because it includes early years in which very high returns — well over 20 percent — distort the figure so that it is unreliable for present use.

cessive levels, it would be self-defeating to regulate on the basis of market forces, and the most logical alternative is usually cost pricing. Thus the fact that it cannot be made absolutely precise is not grounds for rejecting cost pricing when market conditions make its use advisable.[73] Indeed, some courts have held that costs *must* be at least the starting point for fixing just and reasonable rates in the gas industry. *E.g., City of Detroit v. FPC,* D.C. Cir. 1955, 230 F.2d 810. Even more persuasive is the fact that the Supreme Court upheld the use of cost pricing on a record similar to ours in its *Permian* decision.

Similarly, the producers make a broad attack on the use of average, rather than individual producer costs. We reject this attack as the Supreme Court rejected it in *Permian.*[74] There is nothing in either the Constitution or the Natural Gas Act that prevents the Commission from adopting price ceilings under which some producers will make more money than others or even under which some producers may be in danger of going out of business. The gas-producing industry, as the producers have pointed out to us, is not a true public utility, and one of its characteristics is the possibility of exit from the market.[75] This being the case, we find from the record that the use of average costs, whether it provides a fair return for all businesses

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[73] Imprecision is, however, one of the reasons for the requirement that a regulatory body reassess its rates in terms of purpose and consequences. *See* section IV A (3) *infra.*

[74] 390 U.S. at 818-20, 88 S.Ct. at 1386-87. *Cf.* 390 U.S. at 829-38, 88 S. Ct. at 1392-97 (dissenting opinion of Mr. Justice Douglas).

[75] *See* 3 Joint Appendix, pt. 1, at 77d (examiner's discussion of testimony and exhibits regarding rates of entry and exit).

or not, is lawful and based upon substantial evidence.[76]

In addition to these arguments, which are considerably weakened by their rejection in *Permian*, the producers have pressed one novel argument of a general nature against the cost determinations. They contend that the use of national costs to fix the price of new gas in this case is not substantial evidence because national data contain elements that seriously distort the costing of gas in Southern Louisiana. The producers' authority of strongest reliance is the Supreme Court's post-*Permian* decision in *Baltimore & Ohio R.R. v. Aberdeen & Rockfish R.R.*, 1968, 396 U.S. 87, 89, S.Ct. 290, ____ L.Ed.2d ____. The case condemns the use in railroad price regulation of average costs for an aggregate region when cost elements from part of the region may distort the calculation.[77] There are several reasons, however, why we find that decision inapplicable to the case before us. In the first place, the use of national figures here is based in part upon findings that these costs are the best available

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[76]A different question would be presented if the persons regulated were prevented in some manner from going out of business even when revenues fell below costs.

[77]The Court held that railroad rates for a route spanning two territories, served by two or more carriers in cooperation, cannot be divided among the carriers on the basis of costs for both territories taken together if the costs of lines in one territory distort the cost findings so derived for lines in the other. In the absence of a finding that there is no distortion, said the Court, the unadjusted costs for either territory or for the whole are not substantial evidence.

index to costs in Southern Louisiana,[78] despite inclusion of areas that are not of the same character as this region.[79] Secondly, the Commission has found that new exploration and development is national in scope. The operation of a particular piece of railroad trackage, on the other hand, is local to the place to be served; the supply of railroad service cannot be moved wherever it can be provided at least expense.[80] We accordingly hold that *Aberdeen & Rockfish* does not modify *Permian* approval of national costing in gas producer regulation and that it does not require reversal in this case.

Next, we must deal with the producers' contention that the Commission relied upon stale, unrepresentative data in making its cost findings. The staleness of the record is a serious problem. It is now 1970, and we are reviewing a case in which the record before the examiner closed in 1965. It is a case setting rates for a fast-growing, changing industry in a changing economy. The full Commission, which rendered its decision in 1968, was able to consider some data covering years as recent at 1966, and even this

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[78]The examiner, after extensive consideration, concluded that Southern Louisiana costs were probably slightly lower than those for the nation. 3 Joint Appendix, pt. 1, at 221d-31d.

[79]The producers contend, for example, that costs for the Hugoton-Anadarko area are significantly lower since reservoirs are shallower and should be excluded. The examiner's overall comparison of Southern Louisiana with national costs, however, is more to the point.

[80]There are limits to the movability of gas exploration, too, since a pipeline "cannot be moved around like a garden hose." *See* E. Neuner, *supra* note 9, at 282; note 101, *infra; Staff Report* at 17.

is data that there is reason to expect may already be stale.[81] Staleness of the record, however, is not itself a reason for reversal. *ICC v. Jersey City*, 1944, 322 U.S 503, 514-15, 64 S.Ct. 1129, 1134-35, 88 L.Ed. 1120;[82] *see also United States v. ICC*, 1970, 38 U.S.L.W. 4129, 4137. Much of the problem is attributable to the difficulty of the regulatory undertaking in light of the procedures currently available. Procedures must improve as the experiment of area regulation becomes better understood. Turning to another type of staleness argument, we are not impressed with the producer's complaint that the Commission chose to base some of its findings on older data than the most recent available. These choices were based upon findings as to greater reliability or representativeness of the data used.[83] Moreover, in such cases the Commission did not fail to consider the most recent data in the record, and it adjusted its findings to allow for rising or falling cost trends. Most importantly, it made a finding that costs as a whole during this decade had been remarkably stable (or were even declining slightly) and were likely to remain so, and this finding is based upon substantial evidence.[84]

Having made these determinations, and having inspected the producer's objections to specific cost cal-

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[81] *Compare, e.g.*, 4 Joint Appendix, pt. 1, at 546d (Commission's Opinion, calculating FP ratio at 1.37 for recent years in 1966) *with* Brief for Amerada Group at 17 (indicating FP ratio of approximately 0.62 for 1968, calculated from Bureau of Mines figures).

[82] It is to be noted that the *Permian* case, too, was eight years old when the Supreme Court issued its opinion.

[83] *See, e.g.*, note 72 *supra*.

[84] *See* 4 Joint Appendix, pt. 1, at 666d-76d (Commission's Opinion).

culations, we find that detailed discussion of these calculations would be of little value at this point. The producers point to, and adopt in part, the dissent of Commissioner Carver to the Commission's opinion on rehearing, which raises disturbing criticisms as to nine different types of cost determinations, which, if they had been determined differently, could be aggregated to increase the total by about 4.0 cents.[85] We think this imprecision in cost pricing is completely unavoidable, but the law allows the Commission to use cost pricing nevertheless. Moreover, Commissioner Carver did not present his four-cent increase for general approval, but instead stated that "it is certainly evident that not all of the above adjustments should be accepted." The thrust of the dissent, we think, is that

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[85]The Commissioner's computations produced the following:

Item	*Impact in ¢/Mcf*
22-year depletion period	0.48¢
Time lag of 1.57 years	0.28
Drilling costs — successful well	0.29
Related	
Lease acquisition	0.09
Return allowance	0.43
Unit capitalized outlay	0.31
Exploration and development	1.90
Dry Hole	0.19
Liquids credit	0.25

He added that "I have no idea that all or any of these figures are precisely correct; I think the Commission and its staff has no better idea. . . ." *Id.*

We find the arguments in this dissent to be strong ones, but it is not our task to choose which method we could use. The Commission has followed the cost method in this case, and we cannot reverse its decision here.

We have inspected the Commission's findings as to each of the cost items attacked by the producers with some care. Although we do not discuss each individually in order not to lengthen an already lengthy discussion (*cf.* notes 29-32 *supra*), we find each to be supported by substantial evidence.

the Commission should not have relied upon cost calculations floating in a vacuum but should have reviewed its computations in light of supply, demand, and other market forces (a proposition with which we definitely agree), and should have given greater attention to the settlement agreement proposed by several of the parties.[86] We reject the contention that cost pricing is so imprecise as to make its use unlawful and hold that the Commission's findings here are based upon substantial evidence. We proceed next to the important issues of supply and market, which we consider to be the key to the producer's attacks on the imprecision of cost pricing.

D. *Commission Findings as to the Consequences of Its Orders on the Gas Industry and Market: The Supply Problem*

(1) Commission Findings and the Legal Standards

We have reserved the most serious issue in this case for last. The producers contend that the Commission

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[86]4 Joint Appendix, pt. 1, at 1000d (dissenting opinion). The Commissioner stated that he could not decide this case on the basis of *any* cost record.

In light of the imprecision of costs, broad support for the settlement, evidence that the market has at least a procompetitive structure, and cumbersome nature of price regulation, it may be that the settlement arguments advanced by Commissioner Carver are persuasive. In this case, the settlement is championed by the producers, and before the Commission it was supported by gas distributors (whom we classify as representing consumer interests) accounting for over 87 percent of delivery volume. *Id.* at 1001d. Widespread use of the settlement technique would result in negotiation pitting market forces against each other on an aggregate scale, overseen by the Commission.

improperly failed to consider projected consumer demand for gas in relation to supply and that it thus violated the "end result" test of the *Hope* and *Bluefield* cases. These contentions are closely related to the argument that the Commission's cost determinations are imprecise, for the "end result" test is simply that whatever method a regulatory body uses, the result of its effects must be demonstrably in keeping with the purposes of regulation.[87] The FPC must evaluate each rate set against policies as broad as the Natural Gas Act itself. *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 605, 65 S.Ct. 829, 840, 89 L.Ed. 1206. The purposes of the Act encompass not only

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[87] It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important.
FPC v. Hope Natural Gas Co., supra, 320 U.S. at 602, 64 S. Ct. at 288.

In keeping with this statement, we would not have such serious misgivings about affirming this order, with all the infirmities of the Commission's pricing methods, if the Commission had adequately considered its result in a larger context. A reviewing court, which is not privy to the Commission's special knowledge, is not likely to be able to make the assessment of results that the Commission could. We are troubled greatly by the fall in the FP ratio, for example, and cannot know whether it is so serious as to warrant some immediate, extraordinary action by this Court. The point is that without adequate consideration by the Commission of ultimate market impact, even slight troublesome facts assume fearful proportions. In this case, the producers, as well as the FPC Staff, predict a severe gas shortage, with disastrous effects on consumers and the economy alike. This Court has little inclination to join the Commission in presiding over such a result.

reasonably low rates but maintenance of adequate service for the consumer, and the latter objective is the reason for the *Hope* requirement that rates must be "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[88]

The Supreme Court, while affirming the Commission in *Permian*, made it clear that adequate findings along these lines would be required in the future: "Judicial review of the Commission's orders will therefore function accurately and efficaciously only if the Commission indicates fully and carefully the methods by which, and the purposes for which, it has chosen to act, as well as its assessment of the consequences of its orders for the character and future development of the industry."[89]

In this case, as in *Permian*, the Commission refused to make findings as to overall demand for gas either in the nation or from the Southern Louisiana area, and it likewise declined to estimate future supply under its order. Similarly, the Commission refused to make findings as to the advisable level of the RP (reserves to production) or FP (findings to production) ratios, or to assess the consequences of its or-

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[88]Indeed, the *Hope* case interprets the policy of the Act as involving both consumer interests and the autonomous interests of the industry. The Commission must "balance . . . the investor and consumer interests." 320 U.S. at 603, 64 S. Ct. at 288.

[89]390 U.S. at 792, 88 S. Ct. at 1373.

ders on these ratios.[90] The closest that the Commission came to direct exploration of these problems is in its discussion of the FPC Staff's Econometric Studies, a lengthy set of calculations based upon empirical economic relations and designed to show how price, supply and demand are interrelated in the national economy. The Commission rejected these studies as unreliable.[91] Having rejected this quantitative approach, how-

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[90]The Commission's most specific finding as to demand appears to be that "there seems no doubt that natural gas will be a major and vital source of energy for many years to come." 4 Joint Appendix, pt. 1, at 664d. This assessment is practically useless and should be made with far greater specificity in future proceedings.

The Commission also stated that "[w]e must reject the findings-to-production and reserves-to production ratios as not substantially indicative for fixing ceiling rates in this proceeding." 4 Joint Appendix, pt. 1, at 529d. *But see* note 122 *infra*. The ratios need not have been directly considered in price computation, but the effect of the price on them should have been assessed.

[91]We agree that the econometric studies were fatally defective, for the reasons set out in the examiner's decision. 3 Joint Appendix, pt. 1, at 380d-408d. Their most basic and serious defect is their tacit underlying hypothesis that demand will call forth sufficient exploration to meet it regardless of cost or profit considerations. The examiner quoted the following argument advanced by Amerada:

> . . . Thus, Staff's projections indicate that total exploratory wells in 1970 will be 8,900 at the 17¢ assumed national average ceiling price and with competing fuel prices remaining proportional. A 14¢ ceiling price would yield 10,130 exploratory wells while a 20¢ ceiling price indicates only 8,380 would be drilled. Turning to the same year and under the same assumptions, Staff's alternative model suggests 624 successful gas exploratory wells will be drilled in 1970 if prices remain at current levels, with 742 at a 21¢ ceiling and 581 at a 22¢ ceiling. Even more wells are predicted to be drilled at lower ceiling prices such as 10¢ per Mcf. However, there is nothing in Staff's economic hypothesis or in the exploratory equations utilized which requires that we stop at the 10¢ assumed ceiling

ever, the Commission failed to approach supply and demand in either a semi-quantitative or qualitative way.

Instead, the Commission made less extensive findings as to the effect of its rates on the industry. It found, for example, that the costs it had calculated were likely to remain stable for some time to come. This finding is supported by substantial evidence, since costs had, in the past, shown a pattern of stability or even a slight downward trend, and all components of cost, except possibly production operating expense, were shown unlikely to change significantly.[92] Also, the Commission found that the rate

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price. Thus, the Staff equation at a 2¢ ceiling price would predict that the industry would in 1970 drill 268,310 exploratory wells (Ex. 156, p. 9).

This, of course, is more exploratory wells than have been drilled in total since 1940. The reason for such absurd results is that Staff's exploratory equation fails to consider any cost related to exploration or production; it continues to blindly forecast increases in production due to the supposed stimulating effect of low price on demand." (Amerada reply brief, pp. 21-22)

Although we approve the Commission's action in rejecting these studies, we do not approve of its failure to consider supply in relation to demand. It should be pointed out that in doing so the Commission has itself committed an error similar to Staff's. The error is not so serious as that of utterly failing to consider the profit incentive, but the Commission *has* assumed, without supporting findings, that the cost-plus-return price will be *sufficiently* profitable to elicit supply to meet demand, whatever the level of demand. This is circular pricing. If demand rises and cannot be satisfied out of reservoirs that are easily enough found to allow the entrepreneur his profit, demand will not be satisfied. Having found that rigorous mathematical equations could not solve this problem, the Commission should have confronted it in a semiquantitative or qualitative way.

[92] *See* 4 Joint Appendix, pt. 1, at 667d-73d.

of return it had set was commensurate with that of industries with similar risks, and it concluded that consequently the industry should be able to attract capital sufficient to satisfy demand.[93] Its overall assessment of the revenues that would be produced under its rates and their effect was as follows:

Annual revenue reduction from	
Gas-well and oil-well gas under pre-1961 contracts	$ 41.4 million
Oil-well gas under post-1960 contracts	$ 0.1 million
Gas-well gas under subsequent contracts	$ 7.5 million
Total	$ 49.0 million

> We also estimate that under the maximum rates here allowed . . . [annual revenues] would amount to $519 million, or about 18.4 cents per Mcf (not including sizeable revenues from condensates and entrained liquids) and that these revenues will rise steadily . . . .
>
> In our judgment, the revenues allowed . . . . should foster an active exploratory program consistent with both the financial needs of the industry and the protection of the public interest.[94]

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[93] We do not think reviewing courts should accept such conclusionary findings as this after the "experiment" justification for affirmance no longer applies. The Commission should have looked directly to sources and availability of capital.

[94] Joint Appendix, pt. 1, at 683d. The finding as to the total expected revenue is commendably specific. However, it is useless

The Commission did not explain the reasoning by which it arrived at this conclusion. Finally, the Commission examined the place of natural gas in the economy as a whole and concluded that although other energy sources are growing in importance, "there seems no doubt that natural gas will be a major and vital source of energy for many years to come and nothing should be done at this time which would prevent the exploration and development necessary to make available this clean, convenient, economical and increasingly popular energy source."[95]

(2) The Current Supply Situation

Despite the Commission's optimistic conclusion, the circumstances that have developed since its decision indicate a possibility, indeed perhaps a certainty, that the supply of gas is dangerously low. A serious shortage, in fact, may already be unavoidable because present conditions may render any remedial action ineffective in light of the lag time between remedy and result. Thus the producers point out to us that the FP ratio, for the first time since World War II, shows that findings have declined below production. In other words, the gas industry in 1968 took more gas out of the ground than it discovered. Together with a growing production curve, this fact is alarming, especially since it is likely that the FP ratio will remain below 1.0 for the foreseeable future.[96] The producers also

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to persons not privy to the Commission's expertise, because the Commission has simply stated a figure floating in a vacuum and concluded without more that this figure will "foster an active exploratory program."

[95] 4 Joint Appendix, pt. 1, at 664d.

[96] *See* FPC, Staff Report on National Gas Supply and Demand 11 (1969) (projecting FP ratio as declining steadily from 0.92 in 1969 to 0.73 in 1975).

contend that the RP ratio is dangerously low, and despite the frequency with which this argument has been effectively categorized as a "cry of wolf,"[97] we are concerned about it here. A majority of the Commissioners on the FPC have alluded in public speeches to the seriousness of the supply problem.[98]

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[97]The New York Commission states that "In every major appeal, the producers' 'major issue' has been the claim that if the producer position were rejected, the result would be a widespread shortage of natural gas . . . ." Reply Brief for New York Public Service Commission at 14. In *Permian*, the Supreme Court noted that one party had characterized the producers' concern for the RP ratio as a "neurotic preoccupation." 390 U.S. at 817, 88 S. Ct. at 1386 n. 103. The producers there had argued that the ratio should be kept at a minimum of 20 to 1, and there was substantial evidence that lower ratios were acceptable. The Court evaluated the significance of these ratios as follows:

> Nothing in the record establishes as proper or even minimal any particular ratio. We do not suggest, nor did the Commission, that the Commission should not continuously assess the level and success of exploration, or that the relationship between reserves and production is not a useful bench-mark of the industry's future. We hold only that the Commission here permissibly discounted the producers' reliance upon this relationship to establish the inadequacy of its rate structure.

[98]*See* Address by Chairman White, A Regulator Looks at the Electric and Gas Industries with a Sidelong Glance at Investment Analysis, before the Financial Analysts Federation, May 16, 1969; Address by Commissioner O'Connor, Prospects for Future Gas Supplies, before the National Ass'n of Regulatory Utility Commissioners, October 7, 1969; Address by Commissioner Brooke, before the Independent Natural Gas Ass'n of America, September 9, 1969; Address by Commissioner Bagge, The FPC and Area Pricing: The Need for Re-examination, before the Gas Industry Seminar at Oklahoma State University, May 13, 1969.

We take judicial notice of the concerns these speeches express. *See* C McCormick, Evidence § 328 at 704 (1954). (We

And an even more persuasive indication of the immediacy of the problem is the recent FPC Staff *Report on National Gas Supply and Demand,* issued October 1, 1969, which concludes that "only a few years remain before demand will outrun supply."[99]

The Staff Report is, at least from appearances, a careful, considered document. The record in this case does disclose instances in which Staff has been egregiously in error,[100] but we think there is something to its supply and demand report. The report is based upon quantitative projections of demand and several indicia of supply,— precisely the kind of "assessment of consequences" that we find lacking in the Commission's decision here. Demands for Southern Louisiana's gas, according to the Staff report, will be double its 1969 level in 1975. The FP ratio will remain below 1.0. The RP ratio will decline below 11 by 1973 even under the best of circumstances, and there is nothing that can be done at this time to maintain the ratio at its present level. The report further argues, and argues persuasively, that the inevitable decline in the RP ratio will probably cause regional supply deficiencies to come into existence as early as 1973.[101] And

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do not, of course, take judicial notice of the specific facts they state for the purpose of resolving contested issues. *Id.*)

[99] *Staff Report* at 1.

[100] *See* note 91 *supra* (Econometric studies).

[101] A critical ratio will ultimately be reached in each area below which the RP ratio cannot be decreased, meaning that at that point production cannot be increased without reserve additions, according to the Staff Report. But reserve levels at any given time are determined by previous levels of exploration, and there is a lag before new exploration results in addition of usable reserves. Staff has calculated the critical RP ratio for Southern Louisiana at approximately 8. It has projected the

aside from probable short-term deficiencies that cannot be prevented, Staff concludes that "[a] major new government-industry program is needed immediately to insure the continued growth of natural gas service during the next decade."[102]

The projection in the Report focuses on the next five years, and Staff announces its intention to update it at five-year intervals, but some predictions are made for longer terms. It is not too early to begin considering the effect of present gas use on our resources in the far future.[103] The Staff Report, if it is correct,

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future of the RP ratio and determined that the critical level will be reached about 1973 or 1974 under a "business as usual" regulatory program. At that time production, having kept up with demand, will not be capable of being increased, and deficiencies will come about which production from other areas will not be able to pick up because of lack of delivery lines and because they will be approaching the critical ratio. *See Staff Report* at 14-17.

[102] *Staff Report* at 4.

[103] The supply of natural gas is, of course, ultimately limited not by exploration but by the amount of recoverable reserves. The Potential Gas Committee, a group of experts from all segments of the gas industry, has recently estimated the total recoverable reserves in and offshore to the United States and Alaska at 1,227 trillion cubic feet, divided into probable supply, possible supply, and speculative supply. Consumption in 1968 was 19 trillion cubic feet. Address by Commissioner O'Connor, *supra* note 98. In other words, production for something over sixty years would exhaust this estimated supply even at present levels. The situation is aggravated by (1) growing demand and (2) increasing difficulty of finding reserves as one goes from probable to speculative supply areas. *See* Terry, Future Life of the Natural Gas Industry, in Economics of the Gas Industry 275 (Southwest Legal Foundation ed. 1962). Of course, supply from other countries, pipelined in or brought in as liquid (LNG), synthetic gas and other sources, could have an impact on this problem. Staff Report at 47-76. Farsighted gas regulation, however, would take into account

shows that unavoidable gas supply problems in the near future, the middle future, and the far future are not only possible but probable.[104] This prospect needs only to be considered against the huge and growing importance of natural gas in this nation's energy mix.

(3) Disposition of the Supply Problem at this Stage of Review

The possibility of severe gas shortages, together with the Commission's failure to make thorough findings on the matter, present by far the most important and most difficult question in this case. We have serious misgivings about affirming the Commission. Nonetheless, after having considered all factors we find relevant, we have determined that affirmance is the best course.

First, reversal or even a limited remand would serve little purpose in this case. We think our opinion, and indeed probably the circumstances themselves, will notify the Commission that it cannot in the future set prices by cost considered in a vacuum. The Commission has itself recognized the possibility that its prior orders were inadequate and has set new proceedings that will consider precisely the questions troubling us and may well modify the entire scheme here reviewed. If there is a need to do so, the Com-

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the rational development of this depletable supply, perhaps even to the extent of having that development influence present area rates. *See* note 121 *infra*.

[104] Staff Report at 19 (graph showing supply, demand, and deficiency projections into the late 1980's).

mission may, and has in part, set aside the present order pending further determination. The long and the short of it is that the Federal Power Commission is vested with the responsibility to make certain that the gas industry serves the public interest, and insofar as we can tell it would perform this function equally competently whether we affirmed this case or reversed it. Indeed, if immediate action is called for here, we think a reversal in this case would unduly interfere with the Commission's performance.

Secondly, we can understand the circumstances that led to the Commission's order, and we are not sure that its making thorough findings in the instant case would have avoided entirely the possibilities that Staff has raised. It is certain, for example, that Staff did not communicate these possibilities to the Commission in any coherent way during the consideration of this case; in fact, Staff appears to have made major errors that would have aggravated the situation except for the Commission's refusal to adopt them.[105] Furthermore, the producers, who are possessed of most of the information essential to effective regulation, have not always actually advanced the goal of effective regulation. All in all, indications that supply deficiencies are probable were not clearly so clear at the time of the decision we are reviewing as Staff makes them seem now. Certainly, the Commission is now as aware of this new information as we are. We therefore think it appropriate, rather than inspecting the Commission's de-

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[105] *See* notes 39, 91 *supra* (concerning econometric studies and rate of return).

cision by hindsight, to allow the Commission to proceed with its new hearings with the benefit of the new information that has been presented to us.

Thirdly, this Court cannot itself evaluate the supply situation or determine what action is needed. We do not know whether the information that has reached us is correct or not. Staff states that, "For purposes of this report we have accepted at face value all industry-furnished data. Our conclusions must therefore be weighed against the assumed accuracy of our data base."[106] It also states that it is setting forth only one of several possible forecasts, albeit it is the one it thinks most probable. Clearly, even if immediate, decisive action is needed, this Court cannot take it. Since we have concluded that the Commission is on the right course now, our best course is to keep within the proper sphere of a reviewing court. The point is that the probability of shortage based on new evidence is not before us for review; all that is before us is the legal adequacy, and not the wisdom, of the Commission's orders.

Finally, and most importantly, in light of *Permian* we think we are required to hold that the Commission's orders in this case are procedurally and substantively adequate under the law. Whether they are ultimately wise is a question to be presented not to this Court but to the Commission. In *Permian*, the Supreme Court affirmed the Commission on a record similar to the one we have before us. It reversed

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[106] Staff Report at 2-3.

the Tenth Circuit, which expressed concerns similar to ours. It is true that in sustaining the Commission, the Court indicated that it expected the Commission to perform its procedural duty of fact finding better in the future. We do not think that a great deal of improvement can be expected over the Commission's *Permian* opinion, however, since hearings in this case had been going on for seven years when the Supreme Court issued its opinion, and the decision here came out a few months after that decision. Proceedings over those seven years inevitably caused the Commission to focus on certain issues to the exclusion of others. In other words, we think that the "experiment" doctrine of *Permian* is still relevant to our evaluation of the legal sufficiency of the Commission's efforts. It should be added that the Commission has responded to the difficult task mandated by the *Phillips* and *CATCO* cases by creating a regulatory procedure that is at least potentially workable, and that in itself is no mean accomplishment.[107]

At the same time, we emphasize that our affirmance should not be taken in any manner as a judgment that the supply problem is not serious enough to require immediate modification of the order herein sustained. We do not reach this question. It is possible that the Commission may find it advisable to make such an immediate modification or that it might set aside the order affirmed here. The Commission has power to take these actions if it finds them appropriate. We can only reiterate our concern over what we consider to

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[107] *See* notes 5-13 *supra*.

be strong evidence that a supply deficiency is imminent, but we think it especially important, at this uncertain time, to resist hasty action and to place some degree of faith in the body to which Congress has entrusted this question.

IV. CONCLUSIONS AND RECOMMENDATIONS

Throughout this discussion, we have been forced to navigate between the Scylla of disobeying *Permian* and the Charybdis of condoning inadequate Commission findings in the face of a possible supply deficiency. We think *Permian* requires affirmance. However, we are disturbed by what we consider to be excessive reliance by the Commission upon the mere *result* of the *Permian* decision.[108] This reliance shows that the Commission has not read *Permian* carefully enough. At numerous points in its opinion, the Supreme Court indicated that it was affirming the Commission on an inadequate record and that it was doing so only because area rate proceedings were new. Here, we think it appropriate to place a greater emphasis on the ways in which we hope the Commission will do better.

The most serious problem, as we have said, is that of possible supply deficiencies, together with the cor-

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[108] As we have previously stated, reliance on *Permian* is justified by the "experiment doctrine." The case had been commenced seven years before *Permian* and the Commission's opinion issued five months after *Permian*. Nevertheless, we think some deference to the expectations of the Supreme Court would have been appropriate, if only to show the Commission's awareness of them, especially in light of the advance warning given by the opinion of the Tenth Circuit.

relative failure of the Commission to consider supply and demand. Our discussion of the issues should be understood in light of this order of importance.

A. *Needed Improvements in the Commission's Presentation of Cases for Review*

(1) Identification and Explanation of Rate Components

As the Supreme Court stated in *Permian*, "we would expect that the Commission will hereafter indicate more precisely the method by which it intends to proceed."[109] In computing costs, as we have stated, we think the Commission has adequately explained its findings. It should be more precise, however, about its noncost elements and the reasons for their use. Noncost elements influencing a cost-based rate should be clearly labelled as such and their basis explained as specifically as possible.[110] Non-cost factors may be used to influence market variables such as supply and demand, to create price stability, to influence industry structure, to simplify a rate schedule, and for many

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[109] 390 U.S. at 800, 88 S. Ct. at 1377. The Supreme Court had difficulties similar to ours with noncost elements. 390 U.S. at 815, 88 S.Ct. at 1385 n. 97. The Court charitably observed that "the Commission's exposition of these questions might have been more carefully drawn."

[110] It should not be possible, for example, for a party on appeal to characterize a noncost element as a "phantom" tax allowance. The characterization in this case is absurd, but the possibility for it arose as a result of the Commission's timid treatment of the matter. *See* note 43 *supra*. It would be far better if both courts and parties got down immediately to the real issue — whether the noncost element can be justified.

other purposes,[111] but only if they are clearly identified and explained. If the Commission approaches these matters forthrightly, it can expect a reviewing court to give great deference to its expertise, even when it ventures into new territory.

(2) Assessment of Consequences upon the Industry

We have already cited the Supreme Court's language calling for more specific assessment of consequences upon the industry. This assessment should encompass the following three variables, among others: (1) The character and number of individual enterprises that will remain when the order has had its effect (i.e., industry structure); (2) the capital actually available to the industry as a whole; and (3) most importantly, the industry's probable conduct and performance as a result of the order.

Maintenance of a healthy industry structure is an important FPC responsibility.[112] We have heard producer complaints that the use of unexamined average costs will prevent large segments of the industry from recouping investment and will lead to greater con-

[111] *See* 390 U.S. at 815, 88 S. Ct. at 1385, nn. 97-99 and authorities therein cited.

[112] The natural gas industry, even though regulated, is subject to antitrust legislation, and the policies of that legislation should not conflict with the impact of the rate order. If a significant decline in the number of competitors appeared probable, it would be a matter of concern in antitrust law even in a large, fragmented market. *See United States v. Von's Grocery Co.*, 1966, 384 U.S. 270, 86 S. Ct. 1478, 16 L.Ed.2d 555.

centration in the industry, particularly since small producers as a class are subject to higher risks than large ones. We do not know whether this dire prediction represents truth or an overactive imagination, and more importantly we cannot tell from the Commission's opinion whether it knows.[113] The Commission could have cleared up the problem by a few simple findings that should have been a part of its determination — findings as to the approximate number of producers, if any, who might abandon business as a result of the rates as set and as to the subsequent degree of concentration in the industry. If concentration is increasing, the increase should be justified in terms of the public interest.

As to the crucial issue of sources for adequate financing, the Commission's findings, and for that matter the evidence, are almost nonexistent. The Commission has made only conclusionary statements to the effect that capital from outside sources will be available at the rate it has set. This is a tenuous basis for our affirmance. Another court reviewing a regula-

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[113] In this connection, the Commission might well consider the recommendations of Mr. Justice Douglas in *Permian* rather than emphasizing, as it has in its brief, that his was a "solitary" dissent. The use of average costs without examination of results troubled him and troubles us. We agree, as did Justice Douglas, that the Commission may certainly *use* average costs, but it should make some finding of effects so that it will be sure that their use is in the public interest. The majority opinion in *Permian* is authority for the proposition that the Commission does not have to make the assessment Justice Douglas would have required, but the making of that assessment would by no means be incompatible with the majority opinion and would be in the public interest. *Cf.* notes 77-80 *supra* and accompanying text.

tory commission stated, with regard to adequate financing, that a commission must make

> inquiries and findings - judgmental as the latter may often be because ratemakers must be prophets of the future as well as historians of the past - into such things as the capital programs in prospect, what such programs entail in terms of down-payments as well as financing, the cost of borrowing money, working capital needs, the desirable ratio of debt to equity, the incentives required by a stockholder to keep his money in the business and the dividends and growth rates requisite to supply these incentives, the opportunities in these respects provided in comparable businesses, and the related matters which must be prayerfully explored by the conscientious regulator before he can begin to say why he fixed upon 4.87 rather than 6.5 or 3.2.[114]

The Commission has considered few of these matters in this case either prayerfully or otherwise, and this deficiency is of great concern to a reviewing court.

With regard to conduct and performance, the Commission must assess how circumstances other than structure and capital will affect the orderly development of the industry. These concerns necessarily involve some consideration of supply and demand, which is the subject we consider next.

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[114] *D.C. Transit System, Inc. v. Washington Metropolitan Area Transit Comm.*, D. C. Cir. 1965, 350 F.2d 928.

(3) Findings as to Market Variables: Supply and Demand

The Commission must discuss the effect its order will have upon the ability of the gas industry to serve its market. There is no doubt that the Commission has the power to set prices on the basis of cost and that market variables do not necessarily have to influence the calculation, but it must examine even a cost-computed rate against the ultimate statutory purposes it is supposed to be carrying out. This is not a novel proposition. A classic statement of it appears in *Colorado Interstate Gas Co. v. FPC*, written in 1945:

> Far-sighted gas-rate regulation will concern itself with the present and future, rather than with the past, as the rate-base formula does. It will take account of conditions and trends at the source of the supply being regulated. It will use price as a tool to bring goods to market — to obtain for the public service the needed amount of gas. Once a price is reached that will do that, there is no legal or economic reason to go higher and any rate above one that will perform this function is unwarranted. * * * On the other hand, if the supply is not too plentiful and the price is not sufficient incentive to exploit it and fails to bring forth the quantity needed, the price is unwisely low, even if it does square perfectly with somebody's idea of return on a "rate base."[115]

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[115] 324 U.S. 581, 612, 65 S. Ct. 829, 843, 89 L.Ed. 1206 (concurring opinion of Mr. Justice Jackson)

In *Permian*, the Supreme Court stated that the Commission would be expected in the future to explain "the purposes for which it has chosen to act."[116]

From the Commission's findings we cannot know whether the demand for Southern Louisiana's gas is going to double, sextuple, or increase tenfold over the next decade, or whether it is going to remain stable or even decline. From data as to past demand, we have a fair idea that if current conditions hold it will grow at about five percent a year.[117] Predictions along this line are subject to obvious infirmities, but at least the possibilities can be identified and probabilities assigned to them.

Such predictions are necessary because the supply of natural gas must be considered in light of demand. Some areas are more promising than others. The Commission appears to assume, without so stating, that a rate that gives adequate return will elicit enough drilling to satisfy future demand even though some reservoirs are harder to find, but we find somewhat more persuasive the producers' argument that producers will meet demand only if there are enough reservoirs

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[116] 390 U.S. at 792, 88 S. Ct. at 1373. We interpret "the purposes for which it has chosen to act" to mean the conduct and level of performance, or other characteristics, that the Commission is trying to elicit from the regulated industry, and the public interest that it is trying to further thereby.

[117] *See* Staff Report at 11 (chart showing past and projected production). Staff forecasts about six percent.

that promise sufficient return at the rate set.[118] The Commission should make findings as to the increased difficulty of finding greater volumes of gas.[119] From this finding, it should estimate the supply that a given rate will elicit.[120]

We do not mean to imply that the Commission must set rates according to supply and demand. In a situation where the market leads to excessive prices, that would of course be self-defeating. We do not think even that the Commission is necessarily bound, as the producers contend, to set rates that will "satisfy" demand; demand is itself a function of rates; and there might be good reason for not matching it to supply.[121]

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[118]This proposition, we think, is a logical corollary of the proposition that cost pricing is ultimately circular. *See* notes 48-49, 91 *supra*. If present demand is satisfied at a price at which only promising areas are explored, there is no assurance that the same price will cause higher demand to be satisfied. Indeed, there is assurance that it will not if increased production requires exploration of less promising (i.e., more expensive) areas, because entrepreneurs will not explore those areas.

The Commission has found that there are huge virgin areas in Southern Louisiana "untouched by the drill," but this finding, without more, does not show that these areas will be developed to satisfy increasing demand *at the price set*.

[119]In particular, it should make predictions as to the probability of an anomaly in the supply-demand relationship, such as the imminent reaching of a critical ratio. *See Staff Report* at 15.

[120]We are well aware that the producers have not helped the Commission to make this prediction. *See* 4 Joint Appendix, pt. 1, at 885d. Nevertheless, it is the Commission's *responsibility* to make a prediction of this nature as best it can. Indeed, we think the process of area regulation is only as good as are numerous such forecasts made by the Commission, either tacitly or expressly. We would prefer they be express.

[121]For example, the Commission has power to curtail wasteful uses of natural gas. FPC v. Transcontinental Gas Pipe Line Co., 1961, 365 U.S. 1, 81 S. Ct. 435, 5 L. Ed.2d 377. Besides using

All that we are holding is that the Commission must explain the relationship between the level of service, the demand for service, and the price it sets. A reviewing court contemplating the "end result" test cannot in good conscience affirm the Commission unless it knows what the Commission is trying to do.

In evaluating its rate, then, the Commission should go through the following three steps relating to industry performance. It should first estimate the needs of consumer service — in this case, the demand for gas. Next, it should use this determination to fix the level of service at which it is aiming, explaining how that level is related to actual demand in the event demand is not to be fully satisfied. It must then make findings, as specifically as possible, as to how the rate it has set will affect the industry's tendency to meet that level of service. This last step means estimating the gas supply that the rate will bring forth. These are difficult matters to predict, but that is more reason why a reviewing court should not be required to guess at them. More importantly, if the Commission sets a rate on a cost basis and does not itself consider these questions carefully, its conclusionary statements to the effect that the rate is adequate or that there will probably be no need for changes in the future (these are statements that the Commission has made here) amount only to so much whistling in the dark.

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price as a tool to elicit supply, we think it probably has power to use it to provide for the orderly consumption of limited reserves. *Cf.* note 103 *supra*.

(4) Reconciliation of Conflicting Statements

Consistency is the hobgoblin of small minds, and we have tried to avoid undue concern when we have found implications in the Commission's findings to be in conflict with each other.[122] The Supreme Court faced the same problem in *Permian* and commented upon it.[123] We think, however, that the Commission ought at least to recognize inconsistencies and explain why they are present. Unexplained, they cause the efforts of a reviewing court to be wastefully consumed.

B. *Disposition of the Case*

The orders of the Commission are sustained in full. The mandate of this Court should not, however, be interpreted to interfere with Commission action that would change the rates we have approved here. We specifically and emphatically reject the contention advanced by the MGD that the Commission has no power to set aside rates once determined by it to be just and reasonable when it has reason to believe its

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[122] We have had difficulty, for example, with the Commission's categorical elimination of the FP ratio from consideration as compared with its use of the FP ratio to calculate new-gas exploration costs. 4 Joint Appendix, pt. 1, at 529d, 546d. The latter reflects either arbitrary, intentionally circular pricing or a judgment that preserving a certain FP ratio does matter. This is an example of a conflict whose resolution would go to the very heart of our doubts about this case. *See also* notes 50-51 *supra*.

[123] *See, e.g.*, 390 U.S. at 815, 88 S.Ct. at 1385 nn. 97-98

determinations may have been erroneous.[124] In fact, the existence of the new proceedings, which as we understand them will take into account many of the issues whose absence has concerned us here, has been one of the factors we have considered in deciding to affirm the Commission's decisions.

It remains for us to consider the stay ordered by this Court when this appeal began, which has to date prevented the Commission's decision from going into effect. We have determined that, subject to the usual extensions provided by Rule 41, F.R.A.P., for petitions for rehearing and certiorari, the stay should be dissolved unless further ordered. This determination is made without prejudice, however, to the Commission's power to stay its own order or to take any other appropriate action affecting this case.

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[124] Section 16 of the Natural Gas Act, 15 U.S.C. § 717*o* (1963), gives the Commission power to "perform any and all acts, and to prescribe, issue, make, amend, *and rescind* such orders as it may find necessary or appropriate to carry out the provisions of this chapter" (emphasis added).

APPENDIX B

Opinion on Petitions for Rehearing of the
United States Court of Appeals for the Fifth Circuit
No. 27492, et al.
Southern Louisiana Area Rate Cases
(June 16, 1970)

IN THE

United States Court of Appeals

FOR THE FIFTH CIRCUIT

No. 27492

SOUTHERN LOUISIANA AREA RATE CASES
AUSTRAL OIL CO., ET AL,
Petitioners,

versus

FEDERAL POWER COMMISSION,
Respondent.

Petitions for Review of Orders of the Federal Power Commission (Texas Case)

ON PETITION FOR REHEARING

(June 16, 1970)

Before THORNBERRY, COLEMAN and MORGAN, Circuit Judges.

PER CURIAM: In our original opinion, we indicated that there was new evidence of a possible impending gas supply shortage. Our affirmance of the Commission's orders is structured so as to allow the Commission great flexibility in dealing with this problem.

To this end, we indicated that the Commission had authority under section 16 of the Natural Gas Act to stay, modify or rescind any part of its order, notwithstanding our affirmance, if circumstances appearing since the issuance of the orders make a change advisable. Petitioners on rehearing, however, have argued to this Court that the Commission may exercise this power *prospectively* only; that is, petitioners argue that affirmance by this Court would preclude the Commission from reexamining revenues from gas that has already been delivered. We wish to make crystal clear the authority of the Commission in this case to reopen *any* part of its order that circumstances require be reopened. Under section 19(b) of the Natural Gas Act, this Court has the broad remedial powers that inhere in a court of equity, and pursuant to our equitable powers we make it part of the remedy in this case that the authority of the Commission to reopen any part of its orders, including those affecting revenues from gas already delivered, is left intact. The Commission can make retrospective as well as prospective adjustments in this case if it finds that it is in the public interest to do so.

At the same time, we emphasize that our judgment is an affirmance and not a remand. The appropriate place for originally considering what parts of the orders must be reopened in light of new evidence is before the Commission. It may be that the Commission will decide that the refunds it has ordered are just and reasonable or at least that their significance to the public interest is outweighed by the confusion and delay that would result from their reopening. In this event, the Com-

mission will allow its refund orders to stand as they are. Or it may be that the refunds are too burdensome in light of new evidence to be in the public interest. In that case, it is our judgment that the Commission shall have the power and the duty to remedy the situation by changing its orders.

In all other respects, the original opinion of this Court is the final disposition of this appeal.

UNITED STATES COURT OF APPEALS
FOR THE FIFTH CIRCUIT

OCTOBER TERM, 1969

No. 27492, Et Al

SOUTHERN LOUISIANA AREA RATE CASES

AUSTRAL OIL CO., ET AL,

Petitioners,

v.

FEDERAL POWER COMMISSION,

Respondent.

PETITION FOR REVIEW OF ORDERS OF THE FEDERAL POWER COMMISSION (TEXAS CASE.)

Before THORNBERRY, COLEMAN and MORGAN, Circuit Judges.

JUDGMENT

This cause came to be heard on the petition of Austral Oil Co., Et Al, for review of orders of the Federal Power Commission in Docket No. AR 61-2 and RI 60-18, Et Al, and was argued by counsel;

ON CONSIDERATION WHEREOF, It is now here ordered, adjudged and decreed by this Court that the orders of the Federal Power Commission in this cause be and the same are hereby affirmed.

It is further ordered that the stay ordered by this Court, subject to the usual extensions provided by Rule 41, FRAP, for petitions for rehearing and certiorari, should be dissolved unless further ordered, without prejudice, to the Commission's power to stay its own order or to take any other appropriate action affecting this case.

It is further ordered that petitioners pay to respondent, the costs on appeal to be taxed by the Clerk of this Court.

March 19, 1970

Issued as Mandate.
Filed July 14, 1970
New Orleans, Louisiana

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

	Docket Nos.
Area Rate Proceeding (Southern Louisiana Area)	AR61-2
AMERADA PETROLEUM CORPORATION, *et al.*	RI60-18, *et al.*

OPINION NO. 546

OPINION AND ORDER DETERMINING JUST AND REASONABLE RATES FOR NATURAL GAS PRODUCERS IN THE SOUTHERN LOUISIANA AREA

Issued: September 25, 1968

DC-52

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(308,043)

308,043

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

AREA RATES; CERTIFICATES — Small Producer; CONTRACT PRICES; COSTS; DCF-PROJECT METHOD; GAS SUPPLY; INDEPENDENT PRODUCER; MINIMUM RATES; NATURAL GAS ACT — Sections 4(e), 5(a), 16; PIPELINES — Offshore Transportation; PRICE STRUCTURE; QUALITY DIFFERENTIALS; QUALITY STATEMENT; RATES — Independent Producer; RATE DESIGN; RATE INCREASES; REFUNDS — Independent Producer; REGULATIONS — Filing; SETTLEMENT; SPECIAL EXEMPTIONS

Before Commissioners: Lee C. White, Chairman; L. J. O'Connor, Jr., Charles R. Ross, Carl E. Bagge, and John A. Carver, Jr.

	Docket Nos.
Area Rate Proceeding (Southern Louisiana Area)	AR61-2
Amerada Petroleum Corporation, *et al.*	RI60-18, *et al.*

OPINION NO. 546

OPINION AND ORDER DETERMINING JUST AND REASONABLE RATES FOR NATURAL GAS PRODUCERS IN THE SOUTHERN LOUISIANA AREA

(Issued September 25, 1968)

WHITE, Chairman:

INTRODUCTION

This is the second proceeding instituted by the Commission to determine just and reasonable rates for natural gas producers under the area rate approach. The first area rate hearing was initiated on December 23, 1960, to determine just and reasonable rates in the Permian Basin area. The decision in that case was issued on August 5, 1965.[1] The subject matter of the present proceeding is

the Southern Louisiana area consisting of the portion of the State of Louisiana lying south of the 31° parallel and including all areas, both State and Federal, in the Gulf of Mexico off the shore of Louisiana. The Southern Louisiana area, including the offshore area, constitutes at the present time and for the foreseeable future a principal area of development of natural gas in the United States, and the just and reasonable price for gas from that area is thus of prime importance to the natural gas consumer and to the natural gas industry as a whole.[2]

Pursuant to Section 5(a) of the Natural Gas Act we are here establishing future rates for jurisdictional sales of gas by producers in the Southern Louisiana area. In the order instituting the proceedings[3] a number of Section 4(e) increased rate filings and Section 7(c) certificate applica-

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[1] Area Rate Proceeding, Docket No. AR61-1, Opinion No. 468, 34 FPC 159; rehearing denied, Opinion No. 468-A, 34 FPC 1068, modified 34 FPC 1286; Commission's orders sustained in their entirety, *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968).

[2] In terms of total capital investment the natural gas industry is the sixth largest in the industry.

[3] Order issued May 10, 1961, 25 FPC 942.

tions were included. The certificate proceedings subsequently were severed and decided separately. In addition to the 252 present respondents to the Section 5 investigation, 199 Section 4(e) proceedings are before us for decision involving 70 producers.[4]

As in the *Permian* proceeding, the Commission required those respondents having companywide jurisdictional sales of more than 10 million Mcf in 1960 to file certain nationwide and area cost, revenue, production, and other operational data for that year on what has become known as the "Appendix B" questionnaire form.[5] Respondents making companywide jursdictional sales of less than 10 million Mcf annually were permitted to report on a separate, simplified form designated "Appendix C". In addition, all respondents who during 1960 were operators of any leasehold in the Southern Louisiana area from which gas was produced and sold subject to the Commission's jurisdictions filed certain operating data, chiefly drilling

costs, required by an "Appendix A" questionnaire. The information thus secured was composited by staff and the composites were distributed to the parties. Although some questionnaires sent out were not returned, and the data provided in a number of others proved to be not compositable,[6] staff was able to prepare separate, composite cost-

[4] A complete listing of the parties is contained in Appendix A to this opinion.

[5] Order issued May 25, 1962, 27 FPC 1038.

[6] Out of an original 248 respondents, 119 filed either Appendix B or Appendix C. Of 49 Appendix B respondents, two were deleted by Commission order, with data from the other 47 being composited. Of the Appendix C filings, 34 out of 70 were usable. The Appendix A filings totaled 131, of which eight were rejected as incomplete or deficient and thus not composited.

of-service studies representing 47 Appendix B companies and 34 Appendix C producers. The 81 companies whose information was composited accounted for almost 85 percent of the natural gas production and 87 percent of the liquid production in the Southern Louisiana area reported in the Louisiana Conservation Commission's report for 1960. Of this amount 82 percent of the gas and 85 percent of the liquids come from the larger Appendix B companies.

The proceeding is before us at this time on exceptions to the initial decision of Chief Examiner Zwerdling, issued on December 30, 1966. Twenty-five briefs on exceptions were filed individually or jointly, representing two States, 81 producer-respondents, 10 interstate pipeline companies, 111 gas distributors and a number of other interested parties and associations and the Commission staff.[7] We are indebted

for the excellent presentations, both in the form of the evidentiary development and in the briefing made by all parties to the proceeding and especially those made by the group participants, notably the Amerada Group (Amerada), an association of a large number of the major producers, and the Associated Gas Distributors (AGD)

[7] Briefs on exceptions were filed by: Hunt Oil Company, *et al.*; Placid Oil Company; Bradco Properties, Inc., *et al.*; E. Cockrell, Jr.; The Superior Oil Company; Perry R. Bass (Operator), *et al.*; Philadelphia Electric Company; P. R. Rutherford; The Atlantic Seaboard Corporation, *et al.*; Alfred C. Glassell, Jr., *et al.*; Independent Petroleum Association of America; Public Service Commission of the State of New York; The California Company, a Division of Chevron Oil Company; Sun Oil Company; Southern Natural Gas Company, *et al.*; Union Texas Petroleum, a Division of (footnote continued on next page)

(308,046)

and Municipal Gas Distributors (MGD), two groups of distribution company intervenors.[8] A two-day oral argument was held on May 15 and 16, 1967.

SUMMARY OF CONCLUSIONS

To summarize our conclusions at the outset, we herein set base area prices for gas subject to the Louisiana severance tax of 18.5 cents per Mcf for all casinghead gas and pre-1961 gas-well gas (including residue gas derived therefrom); 19.5 cents per Mcf for gas-well gas sold under contracts dated January 1, 1961 through September 30, 1968; and 20 cents per Mcf for gas-well gas sold under contracts dated October 1, 1968 and thereafter. For gas not subject to the Louisiana tax the base area rates are set at 1.5 cents per Mcf below those prescribed for taxed sales. The rates so established will be continued until such time as they are changed by the Commission. These rates will not be subject to refund if the rates are later

lowered, and the filing and collection of increases above such rates, subject to refund, will not be permitted unless

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[7] (continued)
Allied Chemical Corporation; Municipal Gas Distributors Group; Southwest Gas Producing Co., Inc.; the Associated Gas Distributors; Amerada Petroleum Corporation, *et al.*; Shell Oil Company; Joinder by Colorado Oil and Gas Corporation, *et al.*; Agnes Cullen Arnold, *et al.*; State of Louisiana; and Commission staff.

The following parties filed briefs opposing exceptions: Shell Oil Company; E. Cockrell, Jr.; Philadelphia Electric Company; Bradco Properties, Inc., *et al.*; Hunt Oil Company *et al.*; The California Company, a Division of Chevron Oil Company; The Associated Gas Distributors; Amerada Petroleum Corporation, *et al.*; Municipal Gas Distributors; Sun Oil Company; and Commission staff.

[8] Other groups which participated on a collective basis are listed early in the Examiner's decision and Appendix B thereto.

and until the Commission grants permission for such rate increase filings.

A proportional Btu adjustment is provided, downward for all gas having a Btu content less than 1,000 Btu per cubic foot and upward for gas rated at more than 1,050 Btu per cubic foot. No adjustment is made for gas coming within these limits. Other quality adjustments are provided in the Opinion but are made applicable only to contracts dated on and after October 1, 1968. Refunds are ordered of excessive amounts collected in the Section 4(e) dockets consolidated in the proceeding.

As in Opinion No. 468 we have provided that individual producers may seek special relief from the area rates. We have also simplified the certificate and rate filing procedures for small producers. Finally, we have reviewed the evidence concerning the need for minimum rates and conclude that minimum rates are unnecessary in Southern Louisiana.

308,048

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THE SOUTHERN LOUISIANA PRODUCTION AREA

Prior to summarizing the Examiner's decision, it is appropriate to review briefly certain well established facts regarding the Southern Louisiana area in order to place the proceeding in perspective. As related by the Examiner, "The Southern Louisiana area here involved covers approximately 54,000 square miles with similar geological characteristics, almost equally divided between land and offshore waters."[9] Although gas production in the area can be traced back to the 1920's, it did not reach significant levels prior to the middle and later 1930's and early 1940's. Development of reserves continued during the war years,

(308,048)

1941-1945, and by the end of the war large supplies of natural gas were awaiting a connection with gas-hungry markets. Large scale interstate transportation did not begin until after the war. The post-war period likewise saw the commencement of offshore exploration, resulting in the discovery and development of huge new reserves. In terms of total proved reserves of natural gas, Southern Louisiana accounted for 22.7 percent of the United States total at the end of 1961, 25.5 percent at the end of 1963, and 27.8 percent at the end of 1967 according to the most recent American Gas Association estimate. In the 1956-1963 period, the area, according to A.G.A. statistics, accounted for more than one-third of the total natural gas reserves.

308,049

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added in the United States. For the years 1960-1962, Southern Louisiana contributed 41.2 percent of the nation's new gas supply and 20.6 percent of its net production. During 1962 offshore leases, from which production has become increasingly important, accounted for 20 percent of the Southern Louisiana area's total gas production. There are currently 47 major producers (producers whose annual

[9] The geographical definition of the area is limited only by the extent of the Continental Shelf insofar as its seaward extension is concerned. As a practical matter, however, it is circumscribed by the industry's technological ability as of a particular time to drill and explore in waters of increasing depth. Thus, although the adjacent Continental Shelf extends out to include water depths up to 600 feet, as of 1963 offshore oil and gas development essentially was limited to water depths of 100 feet or less. We note, however, that recent case materials relating to exploration and development in the Southern Louisiana offshore area show that the industry has developed an ability to drill, explore and lay transmission pipeline in waters as deep as 300 feet or more. *Tennessee Gas Transmission Co., et al.*, Docket No. CP65-356, Tr. p. 1986-87.)

sales of natural gas are over ten million Mcf) in the area and, in 1960, they accounted for approximately 90 percent of the area's total jurisdictional gas sales.

A larger proportion of the gas reserves in Southern Louisiana is non associated gas than is the case nationally. At the end of 1963, non associated gas reserves amounted to 83 percent of the total gas reserves in the area compared to a nationwide figure of 72.9 percent and a Texas figure of 66.6 percent. Most of the gas produced in Southern Louisiana is high pressure, sweet gas and is delivered to pipelines at or beyond a central point in the field rather than at the wellhead.

Pipelines which purchase natural gas in Southern Louisiana at the present time serve 28 states in the central and eastern United States and the District of Columbia. This area accounts for over 70 percent of the population of the country. From a national standpoint, Southern Louisiana is both the most important and the most productive natural gas area in the entire nation.

PRICE RECOMMENDATIONS AND SUMMARY OF EXAMINER'S DECISION

In his initial decision the Examiner has recommended tax-inclusive onshore ceiling rates of 19.5 cents per Mcf for gas-well gas and residue gas derived therefrom, under contracts dated January 1, 1961 and later (new gas), and 18.25 cents per Mcf for all other (old or flowing) gas.[10]

[10] All at 15.025 psia. The cost calculations, with the exception of regulatory expense, royalty, Louisiana production tax and incremental gathering costs were made at 14.65 psia and thereafter converted.

Sales of gas produced in the offshore Federal domain area[11] would, according to the Examiner, carry ceiling rates 1.5 cents per Mcf less, or 18.0 cents per Mcf for new gas-well gas and 16.75 cents per Mcf for flowing gas. The onshore ceilings are below those recommended by the producer-respondents, which vary between 24.0 to 27.0 cents per Mcf, and above the recommendations of staff and the distributor-intervenors. Staff recommended 18.25 cents per Mcf for new gas and 18.0 cents per Mcf for flowing gas; AGD recommended 19.0 and 18.0 cents, respectively, with the 19.0-cent rate being applicable only to a high quality "gold standard" contract.[12] Philadelphia Electric proposed that all onshore flowing and new casinghead gas be priced at 16.25 cents per Mcf, and new non-associated gas at 17.71 cents per Mcf. The Municipal Gas Distributors (MGD) proposed a single ceiling of 16.25 cents per Mcf for all gas.

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[11] Part of the offshore area is within the State taxing jurisdiction of Louisiana, part is clearly outside its jurisdiction and under the control of the Federal government, and part lies within a disputed area. (See, generally, *United States* v. *Louisiana, et al.*, 363 U.S. 1 (1960); 382 U.S. 288 (1965)). As used herein and in the attached Order, the "offshore" designation will be synonomous with the Federal domain area and as meaning the region outside the Louisiana taxing jurisdiction. Conversely, the "onshore" reference will be used with regard to all areas within the State's jurisdiction, both ashore and in the waters proximate thereto.

[12] Witnesses for AGD referred to some 17 features which might be looked to in deciding whether a particular contract qualified under the concept. However, it has not itself set out the standards for "gold standard" gas, apparently leaving these to be set by the Commission. Discounts below the ceiling for gas not meeting the standard would be established by bargaining between the producers and the pipeline-purchasers.

The producers have argued against a rate differential for offshore gas, claiming that the higher costs and risk offshore requires that gas to be priced equally with onshore gas. The Examiner's reduction of 1.5 cents per Mcf follows the recommendations of staff and AGD. On the other hand, MGD, Philadelphia Electric and the New York Commission object to allowing any "bonus" in the form of a cost reimbursement for non-existent State taxes, and hence they would set the offshore gas price 2.3 cents per Mcf below the onshore price, the 2.3 cents being the amount of the severance tax imposed by the State within its taxing jurisdiction.

The Examiner relied heavily on the precedents established in the Commission's *Permian* decision, Opinion No. 468. He affirmed both the two-price system and the finding in *Permian* concerning the directional exploring capability of the industry. His major departure from that opinion was the addition of a 1-cent per Mcf incentive allowance to his nationwide current cost determination in deriving the new gas ceiling. The allowance, as he explained, was made in recognition of "the particular importance of the Southern Louisiana area to the nation's required natural gas supply, both now and for the foreseeable future — and the importance, therefore, of providing an adequate additional incentive, calculated to encourage a maximum level of exploratory activity in the Southern Louisiana area and to encourage the flow of capital for such purposes into that area."

Other than the addition of the 1-cent incentive increment, the Examiner's recommended ceilings were based on industry costs, national for new gas and, for the most part,

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area historical for flowing gas. Using the format established in Opinion No. 468, he determined a nationwide cost of 16.55 cents exclsuive of the producer's share of the Louisiana tax, which when included resulted in a total cost of 18.53 cents per Mcf for new, non-associated gas. The primary modification to the national costs found in *Permian* was in the use of a 14 percent national royalty figure as against the 12.5 percent applied in the Commission's earlier decision. Allowance of the higher Louisiana tax also served to increase the national cost computation for new gas-well gas. Using historical area

costs reported in the Appendix B and C filings he found an onshore flowing gas cost of 18.18 cents per Mcf, which he then rounded upward to an 18.25-cent ceiling.

The Examiner established standards for several quality factors and for delivery pressure, and recommended price adjustments for deviations therefrom based on the net cost of processing the gas to bring it up to standard. Except with respect to Btu, however, he would apply these adjustments only to sales under contracts dated subsequent to the Commission's final order in this proceeding. Since nearly all gas presently sold in Southern Louisiana is of pipeline quality, the Examiner concluded that implementation of the complex procedures set out in *Permian* for making quality price adjustments would serve no useful purpose for gas under existing contracts. Btu adjustments would apply to all contracts regardless of date.

As in Opinion No. 468, the Examiner also recommended a conventionally-determined 12 percent rate of return for both new and flowing gas; he concluded that the reduced risk of finding low quality gas in Southern Louisiana as

compared to Permian, was counterbalanced by the importance of Southern Louisiana gas. Consistent also with *Permian* he recommended: (1) No allowance for Federal income taxes, on the ground that there was no evidence that the industry had an actual liability; (2) Refund of all amounts collected under rates subject to Section 4(e) proceedings in excess of the applicable adjusted area rate (with the issue of refunds below the "last clean rate" left open for further consideration pending its application in a specific situation); (3) A 2½ year moratorium on above-ceiling rate increases commencing with the date of the Commission's decision; (4) Establishment of minimum rates of 13.75 cents tax inclusive and 12.25 cents for offshore gas; and (5) Simplified filing procedures for small producers. The decision made no express provision for special relief from area rates.

The Examiner noted that *Permian* had left the door open for further consideration of the Discounted Cash Flow (DCF) or project method of establishing a new gas price but concluded that the uncertainties and problems connected with the method

as disclosed in the present record rendered it unreliable as a costing method for new gas. He held that the method depends on a number of unsupported assumptions and that, while it may be used by individual producers in choosing between alternative investments, the record does not support its actual use on an industrywide basis for making investments or as a tool for fixing just and reasonable rates.

The Examiner found that, on a unit basis, new gas-well gas costs in Southern Louisiana were no greater than those which existed nationally and that no upward adjustment

was required in translating national costs into area ceilings. He also found that the unit costs had not risen since the test year and are unlikely to do so in the reasonable future, either in the area or nationwide.

Finally, the Examiner found that the 19.5-cent new gas ceiling for onshore gas would generate revenues in 1964 of about 18.64 cents, slightly higher than his 18.53-cent new gas cost. As to new offshore gas, he found all post-1960 contracts appeared contractually entitled to the 18.0-cent ceiling rate. No determination was made as to the adverse revenue effect, if any, of contract prices lower than the ceiling rates for old gas.

AREA RATEMAKING UNDER THE NATURAL GAS ACT

THE PERMIAN DECISION

The history of the development of the area approach to producer regulation was set out in Opinion No. 468.[13] In that proceeding we concluded that the area approach as therein practiced was both statutorily and constitutionally legal and that it ". . . offers a regulatory method which is best adapted to the discharge of our responsibilities for protecting natural gas consumers while providing the greatest incentive to producers to continue their search for needed additions to our gas supply."[14]

Contract prices were rejected as a basis for regulation and the reserves to production ratio was declared to be an inappropriate regulatory standard or tool by which to evaluate the adequacy of just and reasonable prices. Con-

[13] 34 FPC at p. 174-176.

[14] *Id.*, at p. 180.

cluding that the evidence supported producers' claims that the gas industry now has and utilizes a substantial capability to search for gas reservoirs separately from oil reservoirs, the Commission found that a system which priced new gas-well gas, the only gas to which the directional searching applied, on a basis different from that used in pricing all other gas should be adopted as the best means of providing fair prices to the producer while also assuring adequate supplies.

In the *Permian* decision the just and reasonable base area rate for new gas-well gas of pipeline quality was found to be 16.5 cents per Mcf (including taxes) in Texas and 15.5 cents per Mcf plus applicable state and local taxes in New Mexico. For all other pipeline quality gas, and for gas-well gas under contracts dated before January 1, 1961, the just and reasonable base area rate was found to be lower by 2 cents per Mcf. The difference in prices reflected adoption of the two-price system. The new gas-well gas price was based on a current cost study, developed on a nationwide basis, designed to show current finding costs, including both the costs of replacing current production and of making additional findings to meet growing demands. The price for old gas-well gas was determined primarily on the basis of the historical costs of Permian Basin gas-well gas. As a check on the determination of the historical costs, the new gas-well gas costs were back-trended; the results under the two methods were similar. Oil well gas, including residue gas derived therefrom, which the Commission found on the record could not be costed realistically for pricing purposes, was found to have a value equivalent to old gas-well gas of the same quality and accordingly was given the same ceiling price.

Standards were specified for pipeline quality gas and the decision required adjustments to the base prices for

gas which did not conform thereto. The standards included the maximum amounts of carbon dioxide, hydrogen sulfide, sulphur and water that pipeline quality gas could contain. The decision also required that in order for the gas to qualify for ceiling prices it should be delivered at a minimum

pressure of 500 psi.[15] The amount to be deducted from the base area price was to be measured, in each instance, by the purchaser's cost of bringing the gas up to the pipeline quality standard. The Commission further found that in the Permian Basin gas with a Btu content of between 1,000 and 1,050 Btu's per cubic foot was pipeline quality. Upward or downward adjustment from the base rate on a proportional basis was provided for gas outside this range. A minimum price of 9 cents per Mcf was provided for pipeline quality gas where the existing contract rate was below such level.

The decision also imposed a moratorium on the filing of increased rates in excess of the applicable ceiling prior to January 1, 1968, on a finding that in the absence of such a moratorium the producers would be free immediately to file increased rates and continue to collect their contract prices even though they exceeded the rates found just and reasonable. Although the evidence indicated that costs were likely to remain stable throughout the moratorium period, the Commission made it clear that any interested party was free, during its pendency, to request reopening of the proceeding to permit consideration of earlier change. Section 4 rate filings based on indefinite escalation clauses were prohibited unless the rates were at or below the applicable

[15] This was a modification, effected in the rehearing order, from an original minimum requirement of 800 psi.

area rates. Refunds were required for increased rates collected subject to a refund condition, calculated as the difference between the amount collected and the applicable area rate, taking into account quality adjustments. Finally, the area rates were applied to small producers but without the pipeline quality gas adjustments.

The Commission's decision was appealed to the U.S. Court of Appeals for the Tenth Circuit. On January 20, 1967,[16] the court issued its decision affirming in part and remanding in part Opinion 468 and 468-A. Petitions for certiorari filed by the Commission and both consumer and producer groups were granted, 388 U.S. 906, 389 U.S. 817, and the case was argued on December 5, 6 and 7, 1967. On May 1, 1968, the Supreme Court issued its decision sustaining "in their entirety the Commission's orders." *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968).

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PRELIMINARY CONSIDERATIONS

Although some producers continue to assert in this proceeding that the group method is invalid, most appear to have accepted the concept of area pricing, even before the Supreme Court's *Permian* affirmance; to the extent that almost all segments of the natural gas industry are willing to recognize its advantages as against a return to the initial, and largely abortive, attempts at producer price regulation on an individual company cost-of-service basis. The legality of the area approach to producer rate regulation was recently upheld by the Supreme Court in the *Permian* case (slip. op. pp. 15-17). Nothing argued to us in this case warrants a change in the Commission's prior views as to the legality of the area approach.

[16] *Shelly Oil Co., et al.* v. *F.P.C.*, 375 F. 2d 6, 35.

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We also remain convinced of the propriety of the multiple price system, despite the position taken by MGD. MGD opposes a multi-price system primarily on the ground that there is no substantial difference between the cost of new and flowing gas well gas. The implication is that the incentive function of the system fails, and therefore the multiple price system must itself fail for lack of a credible rationale.

However, the propriety of a costing method is not dependent upon its result, and we must be careful to distinguish between costs and prices. We would agree with MGD that if the new gas-well gas cost and the flowing gas-well gas cost were determined to be equal or nearly so, application of a multi-price system might not be justified if prices were to be based solely on costs. In such a case, considerations of both industry and administrative convenience could indicate the application of a single ceiling price for all gas in such an instance. On the other hand, a higher cost determination for new gas-well gas would call for a multi-price system. Further, considering the industry's demonstrated capability to perform a directional search for new gas-well gas, the multi-price system affords the Commission the best opportunity to provide the necessary incentives for continued exploration for future gas while avoiding excessive prices for gas already dedicated.

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Whether the costs of new and flowing gas-well gas approximate each other can only be determined if each is separately calculated. Any attempt to estimate the unit cost of new gas-well gas primarily on the basis of trends or general indices would not be sufficient. We believe both new and flowing gas-well gas should be separately costed.

Within the context of such costings we consider questions of increments for incentives, the cut-off date, and other matters which various parties allege are specifically affected by conditions in Southern Louisiana. Only after this is accomplished is it appropriate to consider the necessity of abandoning the more complex system in favor of a one-price system in practice.

Likewise, we still do not view findings-to-production ratios as significant in helping to determine reasonable rates. We attempt to design rates that reflect a reasonable return. Those rates should encourage producers to search for gas to the extent it can be found and sold. Higher prices might increase findings and lessen consumption. But the respondents do not suggest what the resulting reserves-to-production or findings-to-production ratios would be and why they would be worth the price. Respondents' arguments in this regard do not convince us to approve all contract prices; nor do they demonstrate the propriety of respondents' recommended ceiling rate rather than any other. We must reject the findings-to-production and reserves-to-production ratios as not substantially indicative for fixing ceiling rates in this proceeding.

However, while these ratios should not be used for purposes of determining just and reasonable rates, they do provide a measure of the industry's exploratory effort, and are an important indication of trends in the overall supply situation. As such, they are and will continue to be reviewed by the Commission, along with other pertinent data, in evaluating the effect of the prescribed area rates in light of the Commission's obligation to assure that supplies of gas for the future will be adequate.

CONTRACT PRICES AND EFFECTIVENESS OF COMPETITION

We are again faced in this proceeding with the contention that the interstate market for natural gas is effectively competitive, and that our statutory responsibility for establishing just and reasonable rates will be discharged by a validation of the contract prices. We considered this claim in *Permian* and decided that while negotiated contract prices are an important element for consideration in the determination of area rates, the requirements of the Natural Gas Act cannot be satisfied by reliance on contract price levels as the basic regulatory standard upon which to base just and reasonable rate levels. We adhere to that position in this case. Further, we do not believe that competition in the markets for natural gas, as the facts of that competition in Southern Louisiana are shown in the record, has been or will be adequate to assure consumers just and reasonable rates. Accordingly, we reject regulation by contract price in this decision.

The producers have attempted to demonstrate that the gas producing industry in Southern Louisiana is competitive. The witness for the major producer group judged competitiveness by three criteria: (1) concentration ratios, (2) leadership turnover, and (3) conditions of entry. He applied these criteria to the factual characteristics of the producing industry in the area, and concluded the industry was effectively competitive. The Examiner considered this evidence at some length in his initial decision (mimeo. pp. 8-19), and concluded that it was not relevant to the issue of competition as that issue was framed in Opinion No. 468. We agree with the Examiner. In our effort to evaluate the

competitiveness of the industry in *Permian*, we considered the history of price negotiations, the relative bargaining power of pipeline purchasers and the matter of uncommitted reserves, among other factors. Those considerations are equally important here.

Prior to 1950, United Gas Pipe Line Company was the only major pipeline purchaser of gas in Southern Louisiana. In 1950, Tennessee Gas Transmission Company and Transcontinental Gas Pipe Line Corporation joined United as purchasers. By

1959, eight additional pipeline companies were purchasing gas in the area. During the period 1950-1962, the total volume of gas purchased by the major pipelines in Southern Louisiana rose from less than 100 million Mcf to over 2 billion Mcf, an increase of approximately 2,000 percent.

Through 1950, the then unregulated field price did not exceed 9 cents per Mcf. In 1951, Southern Natural Gas Company contracted for gas at 12 cents per Mcf, and in 1952, while most other pipelines were still paying between 7.8 and 10 cents per Mcf, United Fuel Gas started purchasing gas at prices between 16 and 21 cents exclusive of tax. American Louisiana Pipeline Company purchased gas at 20 cents per Mcf, excluding tax, in 1953. Once the higher level of prices was attained it became a floor for future prices as producers were unwilling to contract for less, knowing that other producers would similarly leave reserves unsold at lower prices. Meanwhile the level of prices paid under older contracts steadily increased due to the operation of favored nation, periodic escalation, and redetermination and renegotiation clauses. The price spiral peaked in 1958 when Trunkline Gas Company contracted

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for gas at an initial price of 24.05 cents per Mcf, including tax.

The pattern of pipeline purchasing activities in Southern Louisiana has been characterized by a pressing need to obtain large blocks of uncommitted reserves at given times, not necessarily of their own choosing, in order to maintain their competitive positions in developing markets. Large reserves were also needed to support initial certification of the newer pipelines. The pipelines were able to obtain the necessary reserves, but only at ever increasing price levels. Moreover, the operation of favored nation and price redetermination clauses in existing contracts served to assure all producers the highest going rate, and greatly increased the overall cost of gas to the purchasing pipelines, distribution companies, and ultimate consumers.

The record here indicates that the costs of the individual producers vary substantially, but there is no evidence that these cost differentials have been reflected in the negotiated prices. While certain aspects of the gas producing

industry, such as lease acquisition activity, are undoubtedly competitive, there is no evidence of substantial price competition in the sale of gas to pipelines.

Another factor inherent in the consideration of contract prices is the relative bargaining position of sellers and purchasers. We considered this problem in *Permian,* and concluded that the pipelines purchasing gas in the Permian Basin were so disadvantaged in their bargaining position as to invalidate the concept of regulation by contract price. We reach the same conclusion here. This record discloses that eight independent producers in Southern Louisiana accounted for over 50 percent of 1960 sales under FPC

rate schedules (interstate sales). The record here does not disclose any data showing the amount of uncommitted reserves controlled by any producer or group of producers, but the pattern of sales commitments and annual deliveries indicate that a small number of sellers control a large percentage of the gas reserves in Southern Louisiana. We point out that while the necessary information concerning uncommitted reserves is exclusively in the possession of the producers themselves, they have made no showing to rebut a conclusion that there is a concentration of control over the uncommitted reserves in Southern Louisiana.

The large interstate pipeline purchasers in Southern Louisiana periodically require the long-term commitment of large blocks of reserves, as we have pointed out. At any one time the latitude available to the pipelines as to reserve sources or purchasing timing is very circumscribed. Only a few producers may have the necessary volumes available for initial commitment at the moment. Moreover, pipelines pass their gas purchase outlays on to distributors, and ultimately to consumers, through the pipelines' regulated, cost-based resale rates, which is a factor tending to dilute their bargaining motivations. This entire situation enhances the bargaining power of the sellers and often tends to make price a second level consideration to the purchaser.

Based upon this analysis we must conclude that there are serious market imperfections which preclude us from relying upon the free operation of the market, as evidenced by arms' length bargaining, to protect the ultimate consumer from unreasonable purchased gas rates.

The conclusion is entirely consistent with the judicial determinations relevant to the issue of contract prices.

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See, *Bel Oil Corp.* v. *F.P.C.*, 255 F. 2d 548 (CA5, 1958), *cert. denied* 358 U.S. 804; *City of Detroit* v. *F.P.C.*, 230 F. 2d 810 (CADC, 1955); *Forest Oil Corp* v. *F.P.C.*, 263 F. 2d 622 (CA5, 1959); *Atlantic Refining Co.* v. *P.S.C. of New York* (CATCO), 360 U.S. 378 (1959); *U.G.I.* v. *F.P.C.*, 283 F. 2d 817 (CA9, 1960); *P.S.C. of New York* v. *F.P.C.*, 287 F. 2d 146 (CADC, 1960); *U.G.I.* v. *F.P.C.*, 287 F. 2d 159 (CA10, 1961); *U.G.I.* v. *F.P.C.*, 290 F. 2d 133 (CA5, 1961), *cert. denied* 368 U.S. 823; *U.G.I.* v. *Gallery Properties, Inc.*, 282 U.S. 223. For the most recent opinion of the Supreme Court on the subject see *F.P.C.* v. *Sunray DX Oil Co., et al.*, 391 U.S. 9, 25-26 (1968).

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DATE OF DIVISION

The initial decision would fix the date of division between new gas-well gas and old gas-well gas at January 1, 1961. This is the same date fixed in the *Permian* opinion. The distributors and the New York Commission argue that the division date should be the effective date of the order. Amerada, on the other hand, argues that the date of division should fall sometime in the perior between 1950 and 1955 as directionality — the ability to direct exploratory activities toward gas or oil in particular rather than to petroleum products in general — occurred much earlier in Southern Louisiana than it did in the Permian Basin.

For a number of reasons we believe that the January 1, 1961, division date should be adhered to in this proceeding. It was in the latter part of 1960 that we amended our policy statement to establish an initial price guideline in Southern Louisiana.[17] Our pricing policy has given different treat-

[17] Statement of General Policy No. 61-1, 24 FPC 818, First Amendment issued October 25, 1960, 24 FPC 902.

ment to gas dedicated since that date than to older gas. As stated in the *Permian* opinion, we believe that a year-end date is preferable for reasons of administrative convenience and the computation of cost data. The date of January 1, 1961, is the closest year-end date to the time when a two-price system was first established in Southern Louisiana and elsewhere. The use of the same division date as was used in the Permian Basin will ensure equality of treatment in this respect among producers operating in different pricing areas — a producer should not be penalized by having a later division date exclude its gas from the new gas category solely because he chanced to be in one area rather than another, unless strong and sufficient reasons are shown for the different treatment. Multiplicity of division dates throughout the various areas would complicate the administrative structure of gas prices.

There is no factual demonstration that substantial directionality occurred earlier in Southern Louisiana than in the Permian Basin area. The relevant statistical data in this record concerning directionality begins with 1958.

Finally, it should also be pointed out that the cost data presented in this proceeding are oriented for a division date

as of the end of 1960. While this alone would not be sufficient ground to establish the date of division, it is one more reason why the Presiding Examiner's determination in this respect should be adhered to. Accordingly, gas-well gas, and residue gas derived therefrom, flowing under contracts dated January 1, 1961, and for a number of years thereafter will be considered new gas while all other gas will be classified as flowing gas. Also, the Examiner has rightly found that the date on the face of the gas-well gas sales contract

should be determinative of whether the sale is to be considered as new or flowing gas. As explained below, we shall also establish a third vintage price for future gas-well gas contracts.

NEW GAS-WELL GAS COST

In Permian, the Commission developed the new gas-well gas cost, on a nationwide basis, using recent industry-wide cost data obtained from various published sources. The decision to cost new gas-well gas separately was based essentially on a finding that the industry had established such a degree of directionality that a separate and higher price for gas-well gas, if justified by cost analysis or other non-cost factors, would encourage the search for non-associated gas. It was further recognized that any attempt to cost casinghead gas must necessarily be dependent upon various complex allocations of cost between oil and gas, whereas the costing of gas-well gas is far less dependent on such controversial allocations. In addition, we recognized that it would be unrealistic to assign large exploration expenditures to casinghead gas since this gas is found largely as a by-product in the search for oil. Another persuasive reason for separately costing gas-well gas in the present proceeding is the fact that the preponderance (approximately 83 percent) of all gas produced in Southern Louisiana is non-associated.

There are several reasons for deriving a nationwide rather than an area cost. First, a substantial amount of the new gas-well gas cost is represented by expenditures for exploration and development (E&D). There is general agreement that E&D is undertaken by individual companies, and by the industry at large, on a nationwide basis. It would be difficult, if not impossible, to isolate E&D by individual area. Second, most of the cost data necessary to estimate the cost of new gas-well

gas is available only on a nationwide basis. These considerations are equally relevant in determining the costing technique to be used in this proceeding.

The parties proposed various costing methods. The producer-respondents advocate the Discounted Cash Flow or Project method to estimate the cost of new non-associated gas. In Opinion No. 468, the Commission discussed the alternative of a project method of costing. That method involves, among other things, the "capitalization" of E&D costs. While the project method was rejected in *Permian*, the Commission nevertheless said that "capitalization of E&D may well be a useful approach and we do not foreclose in succeeding cases further consideration of this alternative method of costing or of improvements in the cost-finding techniques here employed." (34 FPC 193).

The Examiner's decision includes a full discussion of the project method as it was presented in this proceeding and discusses both the asserted advantages of the method and the claimed defects in the producers' presentation. The Examiner concluded that the many uncertainties and problems connected with the method render it unreliable for the costing of new gas-well-gas in the instant proceeding. We agree with the Examiner's conclusion that the DCF-project method can not be adopted by this Commission as a primary costing method. However, because it has received extensive attention, we discuss the method and its application further in our appendices. Appendices B and C to this Opinion contain, respectively, a description of the DCF-project approach, a discussion of "true yield" rate of return relating to the project method, and an application of the DCF-project method for comparison to the new gas-well gas cost study which is adopted in this Opinion.

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The Associated Gas Distributors propose a costing virtually identical to that sponsored in the *Permian* proceeding by the California Distributors, and adopted, with certain modifications by the Commission in Opinion No. 468. This method follows the Commission's traditional practice and the common industry practice of expensing unsuccessful exploration and development costs and capitalizing only production investment costs. The AGD new gas-well gas cost was determined on a nationwide rather than an area basis.

The Municipal Gas Distributors group, on the other hand, oppose the dual costing approach for new and flowing gas,

and also opposes the separate costing of gas-well gas. It proposes a single-price structure based on the historical cost for all gas produced in Southern Louisiana, both associated and non-associated. It argues that a higher price for gas of later vintage is not warranted since it has not been demonstrated that the cost of gas has increased beyond that determined by MGD from the cost data compiled and composited from the Commission's cost questionnaire.

There is little doubt that the allocated cost of casinghead gas would fall below the cost of gas-well gas. However, the Commission has not attempted to include the cost of casinghead gas in with the cost of gas-well gas. We did not do so in the *Permian* case and we shall not do so here. The computation of casinghead gas cost is less accurate than the computation of the cost of gas-well gas. This is so because casinghead gas is the secondary product on leases where it is produced and is substantially more sensitive to minor changes in allocation ratios. Therefore, the casinghead gas cost result finally derived is too imprecise, in our

judgment, to be used as a meaningful measure for pricing purposes.

We have noted MGD's suggestion that the cost yardstick used in connection with the post-1960 gas-well gas price should be based upon historic area cost, as in the case of pre-1961 gas. We agree that area costs do not appear to have risen. Furthermore, we have recognized the propriety of trending; in our *Permian* opinion we established flowing gas costs by backtrending new gas costs. 34 FPC 218-220. Indeed some of the new gas cost components were themselves calculated in part by trending forward certain older data. 34 FPC 192.

Nevertheless, there are good reasons for separately calculating new gas costs, rather than just relying on certain indices to conclude, as MGD suggests, that new gas costs are the same as old gas costs in Southern Louisiana. For one, unit gas cost determinations are complex. We hesitate at this early date in area ratemaking to rely directly on general indicators — such as certain horizontal cost trends — unless those data are used within a comprehensive, supported unit cost analysis. Of course, we rely on general trend data for corroborative or comparative purposes. Also, we are interested in the *national* cost of new gas. But MGD would trend forward *area* flowing gas

costs. National new gas costs (adjusted for local pressure base and production taxes) are important because the source of new gas supplies is now substantially national rather than regional in scope; that is, the Southwest, which includes Southern Louisiana, and which accounts for almost all of the nation's new gas, has become almost one vast common source of gas supply for the entire country.

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In our judgment, composite costs must provide the basis for ultimate prices. We conclude that there should be a separate and independent costing not only of gas-well gas, but of both new and flowing gas-well gas. We reaffirm our conviction that the new gas-well gas cost should be developed on a nationwide basis unless the record clearly indicates that the nationwide new gas-well gas cost is not representative of the cost of finding and producing nonassociated gas in Southern Louisiana.

After considering the present record, it is our conclusion that the general costing techniques adopted in Opinion No. 468 should be followed in this proceeding.

As in the *Permian* opinion, we shall not here establish a separate price for casinghead gas. Although the facts with respect to casinghead gas are somewhat different in Southern Louisiana, no separate price is justified. In the Permian Basin over 60 percent of the gas produced is casinghead gas. Very little of this gas, however, is sold under fixed-price contracts. The bulk of it is sold under contracts calling for percentage payments which we have not separately regulated as to price. In Southern Louisiana, in contrast, casinghead gas as well as gas-well gas is sold under contracts calling for a specific price. About 17 percent of the gas produced in Southern Louisiana in the 1960-1966 period was casinghead gas. In the Permian Basin casinghead gas, in general, is of poorer quality than gas-well gas except as to Btu content. Its pressure is quite low. In Southern Louisiana casinghead gas compares favorably with gas-well gas, even as to pressure. In the Permian Basin the amounts realized from the sale of casinghead gas have been considerably below the historic price level of gas-well gas; while in Southern Louisiana casinghead gas has usually been priced on a par with gas-well gas.

The general desirability of simplicity in regulation and

ease of administration would lead us, other things being equal,

to provide the smallest possible number of prices. We have already noted the virtual impossibility of computing the cost of casinghead gas with accuracy. Under all these circumstances it is our judgment that no separate casinghead gas cost yardstick should be used, nor should a price be provided for casinghead gas separate from that allowed pre-1961 gas-well gas.

In determining a current cost for new non-associated gas in the *Permian* case, the Commission adopted, with modifications, the nationwide costs of new gas-well gas which had been there presented by distributor witness Roseman. In the present proceeding Roseman appeared on behalf of AGD and his *Permian* presentation was made a part of the record by reference. He also sponsored an exhibit proposing minor modifications of his earlier approach. One of the issues for decision is whether the additional evidence introduced in the instant case requires us to modify our earlier nationwide new gas cost determination. We consider the proposed changes in the individual cost components in the appropriate sections below.

EXPLORATION AND DEVELOPMENT COSTS

The California Company (Calco), as well as a number of other producers who operate primarily in Southern Louisiana, contend that area exploration costs should be utilized for both new and old gas costing. This is unlike the *Permian* proceeding where all parties agreed to the use of national E&D figures.[18]

[18] Calco is a division of the Chevron Oil Company, a corporation operating nationwide with a division, Standard Oil of Texas, operating in the Permian Basin area. In the AR61-1 proceeding, The California Company's sister division made no contention that area as opposed to national costs should be used.

(308,067)

We agree with both the Amerada group's witness Porter[19] and the statement by the witness for AGD[20] that it is not

appropriate to determine exploration costs on the basis of expenditures made in the individual pricing areas. Exploration is an industrywide effort directed toward meeting the needs of a national market. Exploration funds generated in one area are uncommitted and may be expended in any other area where the company considers the greatest opportunity to exist. Furthermore, to switch to a local approach for E&D would lead to unachievably high ceilings in some areas and very low cost allowances and cost-based ceilings in some other areas.

We do not overlook the countervailing considerations mentioned by Calco as favoring a local approach to costing. Those considerations have led us to determine production costs (as distinguished from E&D costs) on an area basis for flowing gas. Thus for flowing gas, both local and national considerations are accommodated by our methods, which calculate the E&D allowance on a national basis and production costs on an area basis. As for new gas, the Examiner rightly concluded (mimeo pages 118-

[19] "It is also an accepted fact that exploration is a system-wide, indeed industry-wide, effort that cannot be measured on an area basis. Because exploration funds may be generated in one area and expended in any other area where the company considers the greatest opportunity to exist, the amount spent on exploration in any one area is not
(Cont'd next page)

continued) significant or pertinent to the costing purpose here and it would not be appropriate to determine exploration costs for oil and gas on the basis of expenditures in individual pricing areas, be that determination for for an individual company or for the industry as a whole." (Tr. 12/2655-56).

[20] Tr. 17/5,903.

125) that area data have been available for too short a time to permit a reliable unit cost determination, but that the preponderance of the available evidence indicates that area costs, on balance, are equal to or slightly lower than national average new gas costs.

Finally, the area approach which Calco suggests does not, in fact, identify E&D costs to the Southern Louisiana area. Only the dry hole costs are largely traced to the area. The other costs such as unproved and abandoned leases, which account for two-thirds of the total E&D calculated by Calco, have been allocated, not identified, to the area. The considerations favoring an area approach to E&D, unconvincing to begin with, are not satisfied by methods which allocate national costs to the area.

Dry Hole Costs

The Examiner used the 1958 Census cost of $8.92 per foot, adjusted downward by 3.5 percent for the 1958-60 trend in dry hole drilling costs shown in the Appendix A data, all developed in the *Permian* proceeding and included in this record as Item II by reference. The Examiner's $8.60 per foot cost compares closely with the final 1963 Census cost of 8.69 per foot for dry hole expense. The 1963 Census data confirms the trend which was estimated and projected by AGD witness Roseman in his new gas-well gas cost study as a basis for adjusting the 1958 Census cost to a 1960 cost and is consistent with our own conclusions on the trend in unit costs.

Both Roseman and producer witness Park allocated dry hole footage to gas in proportion to successful gas well footage separately for exploratory and development drilling. Roseman derived a combined ratio of 0.898 feet of dry hole

(308,069)

per successful gas well foot drilled on the average for the period 1951-61, whereas Park, using a shorter (1956-61) period, arrived at a ratio of 0.879. Park multiplied his allocated dry hole gas footage by a $10.56 dry hole cost per foot obtained from the Joint Association Survey, dividing the result by the average yearly additions to non-associated gas supply in the base period to obtain a final figure of 1.58 cents per Mcf. Roseman divided his 0.898 ratio into a successful gas well productivity figure of 587 Mcf per foot drilled to yield a figure for the reserve additions per allocated dry hole foot of 654 Mcf. This was then divided into the cost per foot of dry holes, $9.31 as adjusted,[21] to derive a final cost of 1.42 cents.

As pointed out by the Examiner, the use of the JAS statistics was criticized by the Commission in Opinion No. 468 as reflecting a considerable amount of self selection and over-representation of the larger producers and as inferior to the trended 1958 Census costs. No evidence has been adduced in this proceeding which would cause us to reach a different conclusion.

308,070

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The major objections by the producers to the Roseman method are the failure to use the unadjusted 1958 Census figure for dry hole costs and to the use of the 587 Mcf per foot figure as the average of gas reserves added per foot of successful drilling in the period 1947-61. As noted, we see no problem with the use of the questionnaire data in establishing an industrywide trend in these costs. With regard to the productivity of drilling figures, the producers

[21] The difference between this figure and the $8.60 per foot as referred to above represents other adjustments to reflect the greater average depth of gas wells and related higher costs and the greater success ratio of gas wells at the greater depths. 34 FPC 291-2.

point out that recent revisions for the period indicate that the actual productivity of drilling dropped from 587 to 578 Mcf per foot as the result of changed data on the amount of footage drilled. However, as found in the Examiner's initial decision, the more recent figures reveal an increase in productivity of drilling, reaching 592 Mcf per foot drilled for the period 1950-1964, slightly higher than the 587 Mcf determined in *Permian*. The final figure of 1.42 cents per Mcf does not appear to be the subject of any substantial exceptions and is accepted.

Other Exploratory Costs

Other exploratory costs include geological, geophysical and land department expenses plus exploratory overhead.[22] Witnesses Park and Roseman continue to use different data sources and different estimating techniques. See 34 FPC at 193. We continue to prefer the Roseman approach which relates the G & G, etc. to functionally related expenditures. However, the witnesses computed approximately the same level of expenditures for these items. The parties are thus agreed on the amounts. As shown in the initial decision the final allowance for this item is calculated at a cost of 1.60 cents per Mcf.

Adjustment for Exploration in Excess of Production

The Commission found in Opinion No. 468 that the annual additions to proved reserves have exceeded production on a national basis. To encourage a level of exploration which

[22] Overheads, as calculated here and in our *Permian* opinion, actually include more than exploratory overheads; they also include overhead allowances related to producing leases, etc. This overlaps certain other overhead allowances elsewhere, a matter which we take account of below in Production Operating Expense. The record does not permit correction of overheads here to the appropriate level of E&D.

would continue to provide for findings in excess of production, the Commission charged current production with an additional allowance to provide the industry with the revenues needed to maintain the relationship between the current findings and production. The propriety of such an adjustment was explained in our *Permian* opinion. (34 FPC 193-194). The question is, how much additional allowance is in the public interest?[23]

[23] It is apparent that no similar adjustment is required where exploration costs are capitalized rather than expensed. See 34 FPC 198-199.

As we noted in our *Permian* opinion, "The appropriate ratio for these purposes is a matter for careful judgment rather than scientific formula." One material consideration was and is the recent history of findings-production relationships. Findings have averaged 587 Mcf (at 14.65 psia) per foot of gas-well drilling. We rely on this average here for reasons of consistency with our other calculations and because of the fluctuations of annual findings data over short periods. At 587 Mcf the total findings can be estimated by multiplying times gas footage drilled. Comparisons can then be made with gas-well gas production data:

Year	World Oil Gas-Well Drilling-Footage	MMMcf of Findings: Footage x 587	MMMcf of AGA Gas-Well Gas Production
1961	29,292	17,194	9,740
1962	28,950	16,994	10,005
1963	24,533	14,401	10,866
1964	25,597	15,025	11,533
1965	24,931	14,634	12,302
1966	25,636	15,048	13,241
		93,296	67,688

(308,072)

Thus, for recent years the finding-production ratio has been 1.378.

Amerada's exceptions reiterate the argument for a 75 percent adjustment previously rejected after full consideration

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by the Examiner. We adhere to our conclusion in *Permian* that the adjustment should be 0.37, so that the total E&D allowance will be 1.37 times the cost before adjustment. A 37 percent adjustment times the E&D figure of 3.02 cents results in 1.12 cents as the additional allowance appropriate in our cost study that expenses the dry holes and other exploratory costs.

PRODUCTION OPERATING EXPENSE

The record here is similar in all essential respects to that in *Permian* with regard to the allowance for production operating expense. The various estimates are based on the Appendix B and C questionnaire data. In *Permian* the Commission modified witness Roseman's allowance for this item to reflect the allocation of overhead expense on the basis of direct lease costs and expenses exclusive of DD&A. The result was 2.70 cents per Mcf.

Roseman's computation contained an adjustment to reflect industrywide rather than questionnaire lease condensate and gas production. Since the questionnaire reflected a disproportionately large amount of condensate production, and since operating costs are significantly higher on the condensate leases, the adjustment to the lower industrywide level of condensate production resulted in a downward adjustment in the production operating expense item.

(308,072)

The producers now argue that it is not proper to make a downward adjustment from questionnaire data in determining production operating expense while at the same time making an upward adjustment to industrywide data in determining the liquid credit item. The implication is that the same amount of lease condensate production should be reflected in both items. The essence of the argument is that we have determined a liquid credit for new gas-well gas, but have determined a production operating expense for all (old and new) gas-well gas.

The Examiner made reference in his opinion to the apparent inconsistent treatment of these items, and found that if the condensate production of 108.8 million barrels per year implicit in the liquid credit computation were substituted for nationwide condensate production in calculating production operating expense, the allowance would become 2.89 cents per Mcf rather

than the 2.70 cents per Mcf determined in *Permian*. Adjusted for a royalty of 14 percent instead of the 12½ percent allowed in *Permian*, the figure becomes 2.84 cents per Mcf before royalty allowance.[24]

We agree that the operating expense should reflect condensate production in amounts consistent with other new gas cost determinations. However, there is an offsetting

[24] The Examiner reduced this amount to attribute some costs to reinjected volumes. We agree with the exception taken by the Amerada group that such an adjustment is erroneous because new gas costs are calculated on a net "dry" basis. Attributing costs to reinjected volumes, appropriate for flowing gas, provides a way of allocating costs to liquids that reinjection is designed to recover. However, in our new gas costing we have already taken account of the cost of liquids through the liquid credit determination.

consideration; it concerns overheads in the operating expense. Over 10 percent of the 2.84 cents operating expense is for corporate general costs and expenses; another 5 percent or more is for area, district, and division field costs. These overhead items thus account for 4 mills or more of the 2.84 cents (15 percent times 2.84). However, overheads have already been covered elsewhere in a sub-component called "exploratory and developmental overheads"; which was actually calculated by witness Roseman to cover both production and E&D overheads. (There appears to be a further duplication of overheads; off-lease facilities include some overhead allowances.) A correction should, it seems, be made in the E&D allowance, but the record is inadequate for this purpose. We look forward to an improved record in future cases which will permit correction of these duplications, where and to the extent appropriate. In the meantime we shall retain the 2.70 cents determination, rather than use 2.84 cents, as an interim step in the right direction.

NET LIQUID CREDIT

The Commission decided in *Permian* that it is appropriate in the costing of new gas-well gas to credit producer revenues received from the sale of liquids against the costs of finding and producing the gas-well gas reservoirs in which the liquids are entrained.

The lease liquid portion of the credit reflects revenues received from the sale of condensates separated from gas-well gas at the lease. This credit should reflect industry trends in condensate production and should be representative of current and expected experience. The questionnaire data in this proceeding indicates a historical gross condensate credit of 4.18 cents per Mcf compared with 3.71

(308,074)

cents in *Permian*. We adjusted that 3.71 cents to 3.50 cents in light of other data. Since *Permian* the various published sources of nation-wide data continue to indicate increasing condensate production relative to gas-well gas production. This trend is due in large part to the increasing share of nationwide gas production from new reserves in Southern Louisiana, where gas-well gas tends to be rich in liquids in comparison with other major producing areas.

The Examiner adopted the *Permian* credit of 3.50 cents per Mcf, as recommended by both the staff and major distributors. The producers recommend a gross credit of 2.97 cents based on condensate and gas-well gas production statistics for 1962. These 1962 production statistics, however, reflect mainly the drier, older fields and understate condensate production in new fields. Further, as the liquid credit is intended to indicate the trend of recent industry experience, it should not be based on production of both new and old fields for any single year. Accordingly, we will adhere to the gross lease credit of 3.50 cents per Mcf. This yields a net lease liquids credit of 2.86 cents per Mcf after adjustment for royalty at 14 percent and production tax of 5 percent. However, this amount, which is admittedly conservative, could prove overly so for the future should the relevant data sources indicate a continuation or acceleration in the trend toward increased condensate production relative to gas-well gas production.

Producers also share in the revenues from the plant sale of extracted liquids. It is therefore appropriate to reflect such revenues in the liquid credit. In *Permian* we relied on a stipulation between the parties of 0.20 cents per Mcf for this item. We recognized this was probably a low estimate. (See 34 FPC 1073). In this proceeding distributor witness Roseman calculated a plant credit of 0.75 cents per Mcf, based both on nationwide data and on Southern Louisiana

(308,075)

data as reflected in the questionnaire. Certain of the data upon which

he relied was available for the first time in this proceeding. However he reduced his calculation of 0.75 cents to an estimate of 0.50 cents, a one-third reduction, to allow for the possibility that the southern Louisiana data might not be entirely representative of the national experience and as a margin for error for other possible offsetting factors. The Examiner adopted the *Permian* credit of 0.20 cents because, he felt, Roseman's plant calculations reflected condensates that had already been included in the lease liquid credit allowance.

The plant credit should include all the lease's share of plant liquid revenues not included in the lease liquid credit. It should thus reflect any condensate revenues not already included in the lease credit. There is no factual evidence that plant condensates are already reflected in the lease credit. The producer witness on the subject did not provide any reason for his conclusion that plant condensate is included in statistics for lease condensate. Furthermore, plant condensate is at most only a small fraction of total plant liquids, so that any duplication caused by inclusion of plant condensate would be minimal. We think the downward adjustment from 0.75 cents to 0.50 cents is ample to allow for this possibility. We will adopt a plant liquids credit, including adjustment for tax, of 0.50 cents per Mcf. This becomes 0.43 cents when adjusted for royalty at 14 percent. We believe this plant liquid credit is reliably supported by the evidence and by the analysis of witness Roseman and represents the best estimate of this item available in the proceeding. Adding the plant credit of 0.43 cents to the

(308,075)

lease credit of 2.86 cents yields a total net liquid of 3.29 cents per Mcf, which we will round off to 3.30 cents per Mcf.

308,076

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REGULATORY EXPENSE

In *Permian* the Commission adopted a regulatory expense allowance of 0.14 cents per Mcf derived from the questionnaire data. The estimates in this proceeding range from 0.13 cents per Mcf proposed by MGD and AGD witnesses to 0.17 cents, including royalty allowance, recommended by staff as determined from the questionnaire responses. The Examiner's use of the 0.17 cent figure in both the new gas and flowing gas cost determination has not been excepted to by any party and will be adopted. However, the 0.17 cents includes a royalty component; for purposes of new gas costing, the figure should be restated to preroyalty basis of 0.15 cents; we calculate the royalty allowance separately.

DEPLETION, DEPRECIATION AND AMORTIZATION OF PRODUCTION INVESTMENT COSTS

The finding and developing costs of successful leasehold properties are traditionally capitalized on the books of the producers and recovered through charges for depletion, depreciation and amortization, generally on a unit of production basis. These costs, which include successful well costs, lease acquisition costs and costs of other production facilities, also establish the rate base on which a return is allowed. Of the several new gas cost presentations, only Roseman and Park included DD&A on a basis comparable to the treatment of these costs in Opinion No. 468. The production investment costs determined by the Examiner are based on Roseman's study and are identical to those included in

Opinion No. 468 with the exception of a slight increase in the costs incorporated under the term "other production facilities."[2] We consider herein the Examiner's conclusions and the exceptions taken.

Successful well costs

As proposed by AGD and adopted by the Examiner, Rosenman computed successful well costs at 2.88 cents per Mcf. Rosenman derived the figure by dividing the computed 1960 cost per foot of successful gas-well drilling ($16.89 per foot; the 1958 Census cost, adjusted downward by 5.8 per cent based on the trend shown by questionnaire drilling data) by the 1947-61 average for non-associated gas reserves added per foot of drilling (587 Mcf per foot).[3] The Examiner rejected the computation submitted by producer witness Park, who supported a figure of 2.94 cents per Mcf, because it was based on JAS

data which had been held defective in Opinion No. 468 and which had not been shown here to be any better.

Rosenman relied in part on unrevised *World Oil* data for his productivity of drilling figure. The Examiner noted the producers' contention that use of recently revised *World Oil* footage figures for the 1947-61 period, in lieu of the unrevised data would result in a lower productivity (Mcf per foot drilled) and hence a higher successful well cost per Mcf. However, the Examiner found that subsequent *World Oil* figures for the more recent 15-year period ending in 1964 showed productivity results at least as high as the unre-

[2] The Examiner also noted alternative calculations of $16.94 and 590 Mcf per foot, indicating a successful well cost of 2.87 cents per Mcf.

vised data for 1947-61. If the newer average were applied to Roseman's cost per foot drilled, the cost per Mcf of drilling successful gas wells would actually decline slightly. Under these circumstances, he considered it reasonable to adhere to the 587 Mcf productivity of drilling figure and to the original successful well cost per Mcf. We think he was justified in his conclusion.

Other periods may also warrant consideration: for example, the ten years 1955-1964 with productivity of about 597 Mcf. However, use of these most recent periods for productivity would require a concomitant updating of drilling costs, etc. — a move we consider inappropriate for reasons discussed next in "Lease Acquisition Costs."

Lease Acquisition Costs

The producers contend that the Examiner understated lease acquisition costs when he found such costs amounted to 0.76 cents per Mcf. The Examiner's finding was based on lease-well relationships for 1957-60 and for 1952-1962. The producers would emphasize 1957-1964.

During 1957-1960 annual lease acquisition costs ranged between $400 million and $600 million. In 1961 the figure was again $400 million, but in 1962 it rose to an all-time high of $850 million. Inclusion of the 1962 data would be distorting unless other years were also included. The Examiner was right to include several earlier years when he added on 1961 and 1962.

The latest years raise other problems. The Chase Manhattan figures are $575 million for 1963, $650 million for 1964, and $500 million for 1965. However, there is some question about the 1963 figure. Up to 1963 the Chase Manhattan data had been corroborated by JAS data; JAS reported somewhat higher figures

than Chase Manhattan for 1956-1957 and 1954-1961 and a somewhat lower figure for 1962. But for 1963 JAS reported $376 million, about $199 million less than Chase Manhattan.

We cannot resolve our doubts about these recent data on the basis of the present record. Nor does it appear appropriate to reopen the case in this regard. These proceedings must come to an end. Furthermore, resort to the recent lease data would lead to updating the productivity and drilling cost data, as well. We noted above that productivity data for one recent period, 1955-1964, indicated about 597 Mcf, rather than the 587 Mcf our calculations reflect. Furthermore the 1963 Census reports a reduced well cost of $16.48 per gas well foot drilled. We understand, however, that the $16.48 figure may be in dispute. We shall forego resolution of these offsetting controversies about rising lease costs and declining well costs. For this case we shall rely on the abundant evidence demonstrating a lease cost of 0.76 cents per Mcf related to well costs of 2.88 cents per Mcf.

Other Production Facilities

In *Permian* the Commission calculated a cost for other production facilities (lease equipment, related lease facilities and apportioned overhead investment[26]) of 0.31 cents per Mcf. (34 FPC 198). Applying the same method to the additional information available in the record in this proceeding, witness Roseman recomputed this cost to be 0.40 cents per Mcf. The Examiner adopted this calculation of 0.40 cents.

[26] As we noted in our discussion of exploratory overheads and production operating expenses, there appears to be some duplication or overlap of overhead allowances. The record does not permit precise correction of this error.

(308,078)

The producers complain about the Examiner's reliance on Appendix B data for these purposes. They say that these data are historical rather than exclusively recent and that the data reflect higher well costs than the industry average without commensurately higher facilities costs, thus understating the proper ratio of facilities costs to well costs. However, the Appendix B data have the notable advantage of providing the lease equipment data (but not the off-lease facilities data) by lease type. None of the data which producers rely on identify the lease equipment to gas leases or oil leases. Furthermore, we do not see why historical data as such would distort the ratio or would fail to reflect the general relation

308,079

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between well costs and facilities costs. As for the higher well costs reflect in Appendix B, we note the offsetting considerations that facilities costs are higher on condensate leases and the Appendix B data include more condensate production than does new gas for the overall industry. Finally, the producers' preferred calculations start with JAS figures that are unexplained and uncorroborated. We approve the Examiners' finding of 0.40 cents for other production facilities.

RATE BASE AND RETURN ALLOWANCE

The producer exceptions argue that the initial decision substantially understates the rate base for new gas and that this understatement is demonstrated by the record. The Amerada group cites the Examiner's adoption of an investment rate base in an amount equal to 10 years of capitalized finding costs per Mcf plus an additional year for lag[27] as "the *most serious error* in the Examiner's cost

[27] The time delay between the incurrence of finding costs and the commencement of production.

(308,080)

computation . . ." The producers contend the time lag allowance should be at least 2½ years, which would change the new-gas cost finding by 0.85 cents per Mcf, or 4.5 percent.

Ten years or less is in fact the average period that capitalized investment is outstanding. We know that because the gross investment in producing properties is about twenty times the annual amount of depreciation, depletion, and amortization;[28] in other words, the average property is produced over twenty years. The record figures for Appendix B producing gas leases (excluding shut-in leases) are $2,393,565,854 gross investment and $133,223,254 annual DD&A. That actually indicates a production period of 18 years. Of course, many properties continue producing past the twentieth year. But this late production is at relatively low volumes compared to earlier years. And some properties play out quickly. All in all, the investment is typically written off over twenty years or less. On the average an Mcf waits, at most, ten years to be produced (some gas is produced in the first year, some in the twentieth, etc.; but the average is ten years or less). We allow a return for ten years of waiting.

308,080

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There is an additional waiting or lag period of one year before any production begins. We allow a return for that, too. The producers strenuously object to use of these averages of one year for lag plus ten years production period. The Examiner has correctly pointed out the many reasons

[28] This amount of DD&A is largely determined by the ratio of annual production to remaining production, times the remaining investment. That is, the investment is written off *pro rata* the depletion of gas reserves.

(308,080)

why the producer studies have not been shown reliable and would tend to exaggerate the lag and production periods.

We recognize, at the outset, that the Examiner did not ground his one-year time lag on a specific factual demonstration. Our consideration of the limited evidence of the actual timing of investments, summarized below, and in the discussion of the project method (Appendix B, p. B-4 *et seq.*) leads us to sustain a net time lag of one year for purposes of the specific cost determinations in this case. But we must acknowledge that the available data are not fully satisfactory; and in the future we shall expect our staff and interested parties to undertake a more exhaustive inquiry into the actual patterns of investment time lags, both nationally and for key production areas and subareas, such as the offshore Federal domain of Southern Louisiana.

The empirical lag data available in this record were presented by the producers (Exhibit 248, the Auten-Davis study) and were not available to the Commission in the *Permian* record. So far as they go the data tend to corroborate our one-year lag determination as a national cost findings. The producers' lag data relate to several recent fields. The first year of production from those fields is shown as 1960. Assuming a year's lag from investment to the beginning of production, investments would, on the average, have been made in 1959. The producer data do indeed show that the average capitalized investment was made in 1969: Prior to 1969 $21.5 million was spent for lease acquisition, successful well, and facilities costs. After 1959 $30.4 million was spent on those capitalized items, more than counter-balancing the pre-1959 costs. (Furthermore, the producers noted that additional investments were made after 1964 but not included in the data here.) Thus the average year for capital investment in these fields was 1959, the year before production began.

(308,081)

When we speak of a one-year lag, we refer to the *average* time of expenditure (for successful wells, leases, and facilities) and the time production begins. Of course, some initial expenditures may be made years before production begins; other expenditures occur well after the commencement of production. The lag occurs mainly because of the exploratory time it takes to see if a prospect is worth risking money on and because of

the time it takes to drill wells and construct related facilities. Regulation also necessarily contributes to the lag. It takes from about 40 to 60 days for the Commission to issue routine permanent certificates or temporary certificates pending the outcome of a hearing. The regulatory lag is substantially longer (sometimes many months longer) than 60 days in a few cases where the proposed producer sales must await major pipeline construction that in turn awaits certification after competitive hearings. On the other hand, there is no regulatory lag for expenditures and production on acreage that is already subject to a certificate. New findings on acreage previously dedicated, and for which a certificate has been issued, come on stream as soon as the producer is ready to deliver the gas and the pipeline to receive it. Moreover, producer contracts frequently have prepayment and take-or-pay for provisions which operate to furnish the producer with income in advance of actual production.

Looked at very closely, respondents' data in Exhibit 248 corroborate a finding of one-year's lag, as shown in the table on the next page.

The last column weights, the reported expenditure for time at a 12 percent factor. This is the same sort of weight-

ing as appears in respondents' Exhibit 252 (except that we use a 12 percent factor instead of 10 percent and that we reflect only those outlays which are capitalized in the new-gas cost study). The weighted total is $71,519,200 or 1.057 of the unweighted outlays of $67,675,400.

If the relationship had amounted to 1.12 instead of 1.057 we know from observing the table that the average time for expenditure would have been mid-1958. A relationship of 1.06 (or halfway between the 1.0 of mid-1959 and the 1.12 of mid-1958) would imply the end of 1958 or beginning of 1959; and 1.057 implies the expenditures were made January 11, 1959. That is almost one year before the commencement of production for the related fields, shown by respondents as at the beginning of 1960. Of course, the January 11, 1959 date is spurious because the underlying data are not reliable for such specific calculations. However, the calculations corroborate in a general way that the lag between expenditures and commencement of production is about one year.

Whatever the various, overlapping causes of lag, respondents' summary data suggest that the lag is about one year. The data, however, are faulty in certain regards. As noted by the Examiner, the data may exaggerate lag somewhat. Respondents' own questionnaire solicited lag data for projects in relatively new areas on

(308,082)

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CERTAIN INVESTMENT DATA REPORTED BY RESPONDENTS, ADJUSTED FOR TIMING

($000)

Year	Lease Acquisition	Productive Wildcats	Successful Developmental Wells Plus Related Facilities	Total	Weighted for 12% Factor	
					Factor	Result
1950	506.0	1,703.0	81.0	2,290.0	2.773079	6,350.3
51	60.0	(1.0)	—	59.0	2.475963	146.1
52	89.2	(1.0)	—	88.2	2.210681	195.0
53	163.9	—	—	163.9	1.973823	323.5
54	279.4	346.0	564.0	1,189.4	1.762342	2,096.1
55	614.9	27.8	42.0	684.7	1.573519	1,077.4
56	2,601.4	602.6	77.9	3,281.9	1.404928	4,610.8
57	1,426.9	3,577.1	1,649.0	6,653.0	1.254400	8,345.5
58	989.6	2,554.6	3,527.4	7,071.6	1.120000	7,920.2
59	1,928.4	5,568.2	8,264.5	15,761.1	1.000000	15,761.1
60	553.3	2,364.7	13,402.6	16,320.6	.892857	14,572.0
61	528.3	549.6	5,180.9	6,258.8	.797184	4,989.5
62	173.3	96.7	3,125.2	3,395.2	.711780	2,416.6
63	118.1	128.2	2,478.4	2,724.7	.635518	1,731.6
64	45.1	186.4	1,501.8	1,733.3	.567427	983.5
Totals	10,077.8	17,702.9	39,894.7	67,675.4		71,519.2

Source: Exhibit No. 248 (Auten)

which there was a full spectrum of activity, starting with early seismic and other exploratory efforts. This overlooks many other projects, including offset properties, which are undertaken in well explored areas, which on their own have shorter lag, and which would bring down the overall average lag time."

Conversely, the respondents' data may understate the lag for remote offshore projects where special drilling and completion problems occur and where production must wait for the reach of new pipeline construction, sometimes after competitive hearing. Leasing practices in the offshore Federal domain may also tend to induce a timing of investments different and, perhaps, more lagged than the customary practices onshore. The respondents' data are limited to fields that began gas production in 1960 (or 1959 and 1961 in a few instances) and may not fully reflect the special lag problems for distant offshore fields.[29]

These matters might call for some adjustment of the one-year lag allowance, but they cannot be quantified in the absence of more detailed studies. On balance, we believe the one-year lag cost allowance should be adhered to for the specific cost computation in this case.

The producers have also cited as error the Examiner's failure to reflect growth in new investments. A similar argument was made in the *Permian* proceeding. The Commission's discussion denying the allowance is pertinent in this case and we adopt those views as follows:

"The Major Producer Group contends that in his

[29] We note that the workpapers underlying Exhibit 248 show only two offshore fields out of the eighty covered.

computation of production investment costs the presiding examiner should have included an allowance to reflect future increases in investment. We believe the examiner correctly excluded such an adjustment. Production investment costs are capitalized and recouped, with a return realized from the sale of gas over the period of the life of the investment. This investment is stated in terms of an amount per Mcf of gas found. While the total investment may grow, there is nothing in this record to support a conclusion that there will be an increase in the

amount invested per Mcf of gas found. Accordingly, we believe there is no basis for any additional amount as an allowance for growth in production investment costs." (34 FPC 198-199)

Finally, Amerada claims that if the 20-year average rate base computation is continued, a time value of money adjustment is required. The argument is that by using a rate base computed at one-half the original gross investment, revenues which are deferred to the second 10 years are worth less when received because of the time value of money. However, as pointed out by the Examiner, the argument fails to take into account the fact, implicit in the simplifying assumption, that depletion is not at a constant rate over the life of the reserves but, rather, that the production is substantially reduced in the later years:

"Consequently, even though the computed per Mcf return allowance related to the new gas-well gas found in a given year is constant, the portion of the total return actually earned will be greater in the early years for each vintage of gas than in the later years since more than the average units of gas and condensate, of a given vintage, are produced and paid for in the early years of the depletion period." (Memo p. 99.)

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In our opinion, the greater production in the initial years of depletion of non-associated gas reserves, together with the accelerated production in the related condensate,[30] and the fact that a substantial share of the total eventual investment is not made until various points are reached in the depletion process, compensates for the reduced present value of the deferred revenues.

AGD offered a test of whether these costing methods fail to recognize the time value of money and fail to afford the contemplated return allowance. AGD took the various cost allowances calculated by the Examiner and presumed that prices would be allowed accordingly. These receipts from gas plus the attendant liquids were timed according to production curves which had been presented as a realistic expression of producing operations in a gas field. The revenues were then reduced by current expenses such as royalty, dry holes, etc. The remaining revenues must in sum be adequate to cover return of and return on investment. And, indeed,

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these remaining revenues were adequate to cover return at a 12 percent discount or compound rate of return with enough revenues left over to cover capital investment items.

Respondents disagree at the outset with the various cost components such as 2.88 cents per Mcf for successful wells reflected in the AGD test, and they disagree with the production curves. We will recalculate the test using cost allowances approved by the Commission and using production curves from Item H. These curves are more closely tied to actual production experience than the other curves presented in this record.

[30] P. B6, 7, *infra*.

Respondents also disagree with the AGD test methods in three important regards: they assert that AGD failed to allow for investment lag, wrongly presumed zero income taxes, and wrongly expensed dry holes and other E&D costs instead of treating them as investment items.

As for lag, AGD's use of annual discount factors itself implies that investment occurred one year before revenues; that seems sufficient for lag. In any event, in our recalculation we will "lag" the investment items (successful wells, lease costs, and facilities) according to respondents' own data concerning the lag on such cost components. We use respondents' data although that probably exaggerates the amount of lag. This matter is discussed further in the appendix section on the "DCF-Project method."

As for taxes, AGD's test takes account of tax credits at the beginning, when fields operate at a tax loss, and allows an offsetting tax liability in later years. These tax credits and tax liability add up to zero overall taxes. Respondent witness Fraser's calculations (discussed below under the "DCF-Project method") also assume zero taxes, but respondents appear to prefer affirmative taxes, calculated in a way that simulates the mechanics of the income tax laws. Our recalculation of the AGD test attempts a rough simulation in this regard. The resulting affirmative income taxes, however, are overstated because of our inability to determine and apply an interest deduction, which would reduce or eliminate the taxes. We discuss other aspects of these tax matters when we evaluate the "DCF-Project method." Even assuming the affirmative taxes, the test method shows that our original cost allowances are still adequate to cover the taxes, all the other expenses, the investment and a 12 percent discount rate of return.

Finally, respondents would have us capitalize dry holes, etc., that is, treat these costs as antedating revenues and deserving a return. We deal with this proposal concurrently with our discussion and presentation of the DCF-Project method and the associated true-yield concept in Appendix B. But the point is not apposite here. Here the specific question is whether the approved rate of return is diluted when we use an average period of investment recovery (a year for lag plus half of a twenty-year production period). The answer is no: putting the same investment items into a realistic period of recovery, the discount test generates the same rate of return and total cost results as our original methods.

Our calculations appear in Appendix D[31] entitled "Discounted Cash Flow Test of the Determined Cost of Wellhead Production of Non-associated Gas." The end of the last column on summary Sheet 1 in effect equals zero; that means that our original cost/revenue allowances are adequate to cover expenses, a 12 percent compound rate of return, and investment. Strictly speaking, the negative three-tenths of a cent indicates a result slightly under 12 percent rate of return. However, a shortening of the lag

[31] The DCF-Project study in Appendix C differs from the discounted cash flow study in Appendix D in the treatment of the timing of certain unsuccessful exploration and development expenditures. The Appendix C study treats these losses as initial outlays which are timed before revenues, like successful expenditures. This study is therefore more in keeping with the general concept of a "true-yield" rate of return than the Appendix D study. In the Appendix D study the unsuccessful costs are timed on the basis of income rather than as early outlays. This procedure corresponds to the expensing of exploration and development losses in the new gas-well gas cost study, and the discount factor therefore relates more closely to a conventional rate of return.

period and introduction of an interest deduction would more than offset the negative amount.

Rate of Return

The basic requirements of a fair rate of return are well established. The regulated enterprise is entitled to a return "equal to that generally being made on investments in other business undertakings which are attended by corresponding risks

and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield Water Works & Improvement Co.* v. *P.S.C.*, 262 U.S. 679, 692-693 (1923). "(T)he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *F.P.C.* v. *Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). The proper rate of return must be determined on the basis of informed judgment which considers all relevant facts. *Bluefield* v. *P.S.C.*, *supra*. It should not and probably cannot be determined by reference to any precise formula. *State Corp. Commission of Kansas* v. *F.P.C.*, 206 F.2d 690 (CA8 1953), *cert. denied* 346 U.S. 922 (1954). These broad mandates were established in the course of individual company regulation, but they

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apply with equal force to group regulation such as that to which we are addressing ourselves here.

The respondents recommend a rate of return on a net investment rate base in the range of 16-18 percent based on risk and incentive considerations and on the rate of return earned during the 1947-1963 period by a group of non-integrated oil and gas producers. The staff recommends a rate of return of 9.5 percent principally based on the 1958-1962 earnings of a group of companies comprised of both integrated and non-integrated producers. AGD did not present rate of return evidence, but recommends the 11 percent return previously determined by this Commission in the *Phillips* case, 24 FPC 537 (1960). MGD recommends a rate of return of 9-9.5 percent. The Examiner determined a rate of return of 12 percent. We affirm the determination of a 12 percent rate of return for new gas.

In determining the rate of return to be allowed producers on their sales of natural gas in interstate commerce we must recognize that the exploration for and production of hydrocarbons, gas and oil, are attended by certain characteristic risks. Expenditures for exploration must be made without any assurance of future production. The exploration for hydrocarbons is not bound to be successful on a well basis, a company basis, or even an area basis (although drilling success ratios have been relatively stable on an industry-wide basis).

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One risk is that of exploration itself, and particularly the risk that a series of investments for exploration will fail to yield production. Questionnaire data show that the respondent companies spent over 300 million dollars in 1960 for dry holes, in addition to over 300 million dollars for

geological and geophysical expenses and lease rentals. A well may discover gas, but in less than commercial quantities, and even a commercial well may be below average in productivity. Moreover, there is no assurance of an immediate market once gas is found, due to conditions of oversupply, distance from pipeline purchasers, or other factors. In such instances the well must be shut in to await development of a market. We also recognize the fact that natural gas tends to be found at greater depths than crude oil, and that a major portion of the recent gas discoveries in Southern Louisiana have come from deeper wells located in the offshore area.

While these risks are an incident of the operations of the industry as a whole, they are of proportionately more concern to the smaller producers, who do not have the direct protection afforded by the large scale of major companies. Small producers try to mitigate these risks by sharing in many ventures rather than going alone on a few. They also often rely on expenditures by majors, securing leaseholds through farmouts and receiving test well and dry hole contributions. Small producers pay for this sharing of the risk with an extra royalty or the revealing of geophysical and geological information.

The risks of gas producers may be compared with those of the regulated interstate pipeline companies. The construction and operation of pipeline facilities are entitled to certification by this Commission only upon a detailed showing of economic feasibility. The pipeline companies have abundant sources of long-term gas supplies, and are able to convey the burden of their costs to their customers through their regulated cost-based rates. While pipeline companies are not always protected from competition, they are generally bound to specific customers by contract and generally able to earn the return allowed by regulation. By

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way of comparison it becomes clear that the risks confronting the producing industry are greater than those of the gas transportation industry. We conclude, therefore, that the overall rates of return that have been allowed pipeline companies are not adequate for natural gas producers.

Turning to the recommendations of the parties, we will first consider those made by MGD. MGD's proposed rate of

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return of 9 to 9.5 percent is based on the testimony of witness David A. Kosh, who relied on earnings-price and dividends-price data, with certain adjustments. We have previously referred to earnings-price data in determining a reasonable rate of return for gas producers. *Phillips Petroleum Co.*, 24 FPC 537, 571-574, affirmed *Wisconsin v. F.P.C.*, 373 U.S. 294. However, that type of data can be used only after certain adjustments are made to take account of the difference between stock market prices and the booked investments to which the rate of return would be applied. 24 FPC at 572. It appears more appropriate instead to rely directly on earnings-book data and avoid the need for such intervening adjustments to earnings-price and dividends-price data. (However, with regard to traditional utilities, who do not have diverse unregulated operations, it would be somewhat circular to set utility rates of return according to earnings-book ratios because those ratios are the result of rate regulation in the first place.) In *Permian* we emphasized earnings-book data in determining the reasonable rate of return for gas producers. 34 FPC 203-204.

The producers base their rate of return recommendations on earnings-book data and other evidence presented by Dr. Walter A. Morton. Schedule 9 of witness Morton's

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Exhibit 65 shows the rates of return on total capitalization for 14 industry groups for the period 1947-1962. The group accorded the most significance by Dr. Morton is composed of 13 non-integrated producers. They reflect rates of return significantly higher than any of the other groups of companies. Their average rate of return for the entire 1947-1962 period was 17.8 percent. This is attributable primarily to the high level of earnings in the earlier years. For instance, the return in 1948 was over 30 percent, and the average for the period 1947-1957 was over 20 percent. For the more recent period 1958-1962, during which earnings remained relatively stable, the average return was 14 percent. However by 1965 only seven of the 13 companies were still in operation as independent enterprises. The weighted average return during 1958-1962 for the seven companies was about 12.1 percent.[32]

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The staff argues that the 12 percent rate of return determined by the Examiner is in excess of the upper limit of the range of reasonableness. Staff witness Shaffner recommended a rate of return of 9.5 percent based on Exhibit No. 24, which he sponsored. This exhibit presents detailed comparative earnings data for two groups of companies for the five-year period 1958-1962. In the first group are 9 non-integrated producers chosen according to the following criteria: companies selling 2 million or more Mcf of natural gas annually, publicly held; traded on recognized stock exchanges; and issuing annual reports of their financial position. Dr. Shaffner included every profit-mak-

[32] The 12.1 percent reflects record data (Exhibit 24, Schedule 13) for six of the seven companies: Amerada, Aztec, General American, Midwest Oil, Superior, and Texas Gulf. There is no separate record data for General Crude, the seventh company.

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ing company that met these requirements for the period covered in the exhibit.[33] Eight of the nine companies sell over 10 million Mcf annually. The second group of companies is made up of 26 large integrated producers; that is, companies which in addition to producing oil and gas also have refining and marketing operations. Dr. Shaffner based his return recommendation on the earnings of both groups of companies combined.

The average rate of return for the group of 9 companies, based on annual earnings divided by each year's average capitalization, varies from a low of 11 percent in 1958 to a high of 13.2 percent in 1961. The five-year average 1958-1962 is 12.1 percent. For the group of 26 companies, the return varies only slightly from the 8 percent level, the five-year average being 8.2 percent. The total 35 company average for the period was 9.2 percent.

Staff argues that we should base our determination of the rate of return on the earnings of the entire industry, including the large integrated companies. It is true that the bulk of gas production, both nationally and in Southern Lousiana, is accounted for by the large integrated producers. However, a major portion of their revenues comes from sources other than the production of hydrocarbons. We do not have available any departmental segregation of costs and revenues, and the record does not show the returns earned by the domestic

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production departments of integrated producers. We have

[33] A few companies were not included because they had reported continuing or periodic deficits and were patently nonrepresentative. While the inclusion of these companies would not have significantly affected the average, in fact their inclusion would have had a downward effect.

the earnings experience of integrated companies covering the entire spectrum of their diversified activities, including foreign and domestic petroleum refining, transportation, marketing, and chemical and fertilizer manufacture. But we do not have any basis for comparing the returns on domestic production and the returns on other company activities. We have previously adverted to some of the risks of producers, risks peculiar to exploration and production. To give substantial weight to the earnings experience of integrated companies would be to assume, without justification or proof, either that domestic production returns approximate overall integrated company returns or that such production operations are no more risky than the other company activities and hence entitled to no greater return.

We believe the evidence entitled to the greatest consideration is that pertaining to the non-integrated producers. On the other hand, we recognize that the limited available data on non-integrated producers refers to a few unusually successful companies. Also, the earnings-book ratios of integrated companies deserve to be given some weight. In conclusion, we again find that the reasonable rate of return appropriate to our ceiling price determination is 12 percent. See *Permian*, 34 FPC 200-204.

In *Permian*, we determined a 12 percent rate of return to cover, among other things, the substantial risk in that area of finding gas of less than pipeline quality. Staff argues for a lower rate of return here because the gas-well gas found in Southern Louisiana is virtually all of pipeline quality. However, there are other unusual risks which warrant a rate of return as high as 12 percent in this proceeding. Much of the exploration in Southern Louisiana has been and will be in marshland and offshore areas where the

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environment makes operations more difficult and hazardous. The producers point out that the damage caused by hurricanes in 1964 and 1965 has been estimated at over 200 million dollars. We do not adopt these estimates, nor do we know from this record to what extent the industry is recompensed for such losses through insurance coverage. But the indication is that the tidewater and offshore operations entail special risks not met within the course of operations in inland areas.

The producers stress the need for greater incentive to carry out the necessary exploration for new reserves, and recommend that an incentive be reflected in the rate of return. The price determined here for new gas-well gas will influence.

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the level of future exploratory activity, given the industry's directional capability. We think the price should be and indeed must be sufficient to induce the industry to carry on the search for new reserves, because it is only through a continuing program of exploration that the increasing demand for natural gas can be satisfied. The encouragement of industry exploratory activity is a valid objective of regulation, and is relevant to the determination of the fair rate of return for new gas-well gas. But a reasonable rate of return is incentive enough. Having determined such a reasonable rate of return, we do not think it proper to add any extra amount in the rate of return for the purpose of incentive.

We note that the 12 percent return herein allowed translates to a yield on equity of approximately 13.3 percent based on a capital structure of 85 percent equity and 15

percent debt, with an historical debt cost of 4.5 percent.[34] This may be compared to the equity allowances of 9-11 percent for high debt companies in recent pipeline cases. *Natural Gas Pipeline Company of America*, Opinion No. 544, ... FPC ....., issued July 19, 1968 (9.52%); *Panhandle Eastern Pipe Line Company*, Opinion No. 543, ... FPC ....., issued July 19, 1968 (11.18%); *Midwestern Gas Transmission Co., supra* (9.26%); *American Louisiana Pipe Line Co.*, 28 FPC 482, 485 (9.2%); *Panhandle Eastern Pipe Line Co.*, 25 FPC 550, 551, (10.47%); *Kansas Nebraska Natural Gas Co.*, 25 FPC 448, 452 (10.8%).

As we have discussed, since production investment is to be recovered over an average 10-year period following one year of lag, the resulting total investment base is determined by multiplying the production investment of 4.04 cents per Mcf times 11, which yields 44.44 cents. The annual return is computed at 12 percent of the total investment base, or 5.33 cents per Mcf.

Return on Working Capital

The Examiner determined return on working capital according to the method approved in Opinion No. 468. That method calculates working capital at ⅛ of annual production operating expenses, ⅛ of annual exploration expenses, plus allocated amounts invested in materials, sup-

[34] Long-term debt appears to comprise approximately 15 percent of total capital for integrated producers (Exh. 24, Sch. 2; Exh. 65, Sch. 18; Exh. 121, page 48). These data omit, however, long-term debt secured by production payments, an increasingly important form of financing in the industry. Estimates of long-term debt for non-integrated producers vary widely depending on the sample of companies used (1 percent, Exh. 121, p. 48; 7.5 percent, Exh. 65, Sch. 18; 18.6 percent, Exh. 24, Sch. 2).

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plies and prepayments. Calculated in this manner unit working capital is 1.60 cents per Mcf, which at 12 percent yields a return of 0.19 cents per Mcf.

The producers' claim for a working capital allowance is based on the testimony of witness Morton. He computed cash as a percent of net plant for various groups of companies for the period 1957-1962. (Exhibit 65, Schedule 22). Based on these studies he recommended a cash working capital allowance of 15-18 percent of net plant in addition to an allowance for materials, supplies and prepayments. This is but a variation of the balance sheet approach to working capital. While the method utilized by Dr. Morton eliminates oil inventory items and accounts receivable, it includes marketable securities. These short-term investments are earning assets. They comprise approximately 60 percent of balance sheet cash, 34 FPC 204, and we do not think they are properly included as a working capital item for regulatory purposes.

We addressed ourselves to this problem at some length in the *Permian* opinion. We pointed out that the issue has been before us in previous cases, and that in each instance we have rejected the balance sheet approach. *Cities Service Gas Company*, 3 FPC 459 (1943); *Northern Natural Gas Co.*, 11 FPC 375 (1952); *Panhandle Eastern Pipe Line Co.*, 13 FPC 53 (1954). The courts have upheld us in doing so. *Cities Service Gas Co.*, v. *F.P.C.*, 155 F.2d 694 (CA10 1946), *cert. denied*, 329 U.S. 773 (1946), rehearing denied, 329 U.S. 832; *Corp. Commission of Kansas* v. *F.P.C.*, 206 F.2d 690 (CA8 1953), *cert. denied*, 346 U.S. 922 (1954). We concluded it was not proper to calculate working capital by reference to the balance sheet. We reaffirm that conclusion in the present case. We adhere to the more traditional method adopted in Opinion No. 468 and followed by the Examiner.

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While we reject the balance sheet approach, we are well aware of the industry's need to maintain substantial amounts of cash in order to compete effectively in the market for new leaseholds. Funds for the acquisition of leases have traditionally come from internal sources, since it is generally not

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possible for producers to borrow against unproved properties. We recognize this need in *Permian* by providing a lease play allowance amounting to 0.15 cents per Mcf. We calculated this item as a return on one and one-half times the per Mcf expenditures for lease acquisitions. The present record does not disclose alternative methods of calculating this item; and we will adopt the Examiner's allowance of 0.15 cents per Mcf. Adding the return on working capital of 0.19 cents to the lease play allowance of 0.15 cents yields a total working capital return of 0.34 cents per Mcf which we will round off to 0.35 cents per Mcf.

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FEDERAL INCOME TAXES

It is an essential precept of regulatory law that no income tax allowance should be permitted except for taxes actually paid. *F.P.C. v. United Gas Pipe Line Co.*, 386 U.S. 237 (1967); *El Paso Natural Gas Co. v. F.P.C.*, 281 F. 2d 567, 573 (CA5 1960), *certiorari denied sub nom. California v. F.P.C.*, 366 U.S. 912 (1961); *Alabama-Tennessee Natural Gas Co. v. F.P.C.*, 359 F. 2d 318 (CA5 1966), *certiorari denied*, 385 U.S. 847 (1966). Where this Commission has provided an allowance for taxes which were not actually paid, it has been reversed. *El Paso Natural Gas Co. v. F.P.C. supra*, reversing 22 FPC 260, 267 (1959). It is with

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this principle in mind that we review the evidence concerning federal income taxes.

Schedule Q of the Appendix B questionnaire, Income Tax Statistics, was filed by 49 questionnaire respondents. This information was compiled by the staff and made available to the other parties. Of the 49 companies who filed Schedule Q, 18 claimed to have incurred federal income tax liability on production, exploration, gas gathering, and products extraction operations in the Continental United States for the year 1960. On July 22, 1963, the MGD Group advised the Presiding Examiner that it required additional information in order to properly evaluate the Schedule Q data, and submitted a detailed request for further data from 14 of the 18 companies which reported incurrence of federal income tax in 1960. On October 2 and 3, 1963, the Examiner directed the 14 companies to provide MGD with the requested data. The Examiner's ruling was affirmed by the Commission by order of October 28, 1963, and additional data were received and composited by the staff, and made available to the parties on November 14, 1963. On November 19, MGD applied to the Examiner for the individual company data underlying the November 14 composite, stating that the composited data were not meaningful and could not be used to determine what allowance, if any, should be included in the cost of service for federal income tax. The producers involved refused to provide data respecting their individual tax returns, claiming confidentiality. No party asserts that Schedule Q is adequate to demonstrate whether producers on the average or as a group have an income tax liability on their production operations.

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At this point during the prehearing conference stage of

the proceeding, producer counsel, speaking for the 14 companies and for the Amerada group, stated that no claim for federal income taxes would be made. (Tr. 11/1220-1221, 1225) Three parties, the Hunt group, Sun Oil Company, and The Superior Oil company refused to join this agreement, and stated their intention to claim a federal tax allowance and to submit evidence thereon.[35] As a result of the position taken by the major producer group, the Examiner found it unnecessary to rule on the MGD request for the underlying date[36], and the request was not pursued. Such was the posture of the federal income tax issue at the close of the prehearing stage of the proceeding. In the subsequent development of this issue, no party made use of either the Schedule Q data or the data composited pursuant to the Commission's October 28 order.

The Examiner has recounted in his initial decision the various material adduced by staff witness Dunn and the rebuttal thereto by Amerada. We agree that no weight can be given to Exhibit 31, or to the computations based on that exhibit.

Hunt, Superior and Sun jointly sponsored direct evidence on the tax issue. Their witness, Delbert W. Williams, is a former chief of the natural resources section of the Internal Revenue Service. Mr. Williams sponsored Exhibit 69, entitled "Actual Federal Income Taxes Paid by Corporations Primarily Engaged in Production of Oil and Gas". This Exhibit consisted of tabulations secured from the statistical division of the Internal Revenue Service covering active corporations included in the major industrial group No. 131, entitled "crude petroleum, natural gas, and natural gas liquids". The Exhibit provided tabulated

[35] Tr. vol. 11, pp. 1225-26

[36] Tr. pp. 1277-78.

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data for years 1953-1961. Based on Exhibit 69, witness Williams concluded that companies primarily engaged in the production of oil and gas had paid federal income taxes in each of the years covered by the exhibit, and that the average amount of such taxes was approximately 8 percent of total annual receipts.

The Examiner excluded Exhibit 69 on the ground that it included only companies which were exclusively oil and gas producers and did not include integrated companies, who account for approximately 70 percent of the gas sold in Southern Louisiana. (Initial Decision, p. 112) The Exhibit remained

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in the record, however, as an offer of proof (Tr. 13/4073-74).

As noted by the Examiner, Superior later presented additional testimony by witness Williams to the effect that as a result of a recent change in the "aggregation of properties rule" in the Internal Revenue Code, the statistical data covering the producing operations of the companies included in Exhibit 69 would now be representative of the producing operations of the entire industry. On this basis Superior reoffered Exhibit 69 into evidence. The Examiner again excluded the material on the ground that the argument was speculative in that the effect of the new rule could not be ascertained "until years of actual experience under this amendment . . ."

In a motion to the Examiner dated November 22, 1966, the Hunt group and Superior asked that the record be reopened for the receipt of certain testimony of Mr. Clark W. Breeding based on "newly discovered evidence." This evidence was largely based on a 1966 Internal Revenue

Service publication, *Statistics of Income — 1960, Supplemental Report, Depletion Allowances for Mineral Production Reported on U. S. Tax Returns, Individual, Partnerships, Corporations* (Depletion Study). This publication provides a study of depletion deductions and other income tax data derived from I.R.S. Group 131 and Group 291, "Petroleum Refining and Related Industries." As stated by the Examiner, similar material was introduced in the proceedings in Docket Nos. AR64-1 and 64-2. A lengthy colloquy ensued between the Examiner and producer counsels directed to the question of the representatives of the I.R.S. groupings of companies for the purpose of determining whether a Federal tax allowance could thereby be established to be applied in these area rate proceedings. The Examiner concluded in his initial decision that the proposed new evidence was subject to the same defects which underlay his exclusion of the earlier presentation of Exhibit 69 and the supplemental testimony. Accordingly, he denied the petition to reopen the record.

In their petition Hunt and Superior requested that in the event their motion to reopen were denied, official notice be taken of the cited publication and that serious consideration be given to its effect upon the Federal income tax issue. Pursuant to the request we do take official notice of the I.R.S. publication. The report shows (p. 44) that for Industry Group 131, crude petroleum and natural gas, 2,985 reporting companies with gross receipts of $4 billion had a total taxable net income less deficit of $467,259,000 and a total income subject to tax of $540,655,000. The latter amount excludes tax credits, net operating loss carry-forward and certain other deductions (p. 13). At the then prevailing tax rate this would have created a total tax liability of $281,140,600. However, Exhibit 299-A, p. 8, in the *Permian Basin Area Rate Proceeding*, sponsored by

Witness Robert A. Wilson of the Internal Revenue Service, which we here notice, showed that for a somewhat different (but substantially overlapping) group of returns, the claimed foreign tax credit was $218,148,000 (for companies having a total income tax before foreign tax credit of $294,863,000). More significantly, 18 companies accounted for $223,480,000 of the reported claimed income tax and $216,360,000 of the claimed tax credit. Excluding companies who were principally engaged in supplying field services and subtracting these 18 companies, there were 4,029 returns reporting $39,739,000 of tax compared with $3.4 billion of gross receipts or less than 1.2 percent of tax to gross receipts. The Depletion Study, p. 42, col. 4, shows that $225,842,000 of the reported $281,140,600 income tax was from companies having foreign income and therefore subject to the foreign tax credit. However, only 52 companies had any foreign income.

A similar picture is shown for the Group 131 companies whose data is reported in the *Stipulation of the Parties Concerning the Evidentiary Introduction of Composited Federal Income Tax Data Drawn From Records On File With the Internal Revenue Service In Lieu of the Actual Federal Income Tax Returns of the "All Areas Questionnaire" Respondents.* Exhibit 129-J, *Area Rate Proceeding (Hugoton Anadarko and Texas Gulf Coast Areas)*, Docket Nos. AR64-1, *et al* and AR64-2 *et al.* Exhibit D of that exhibit is a composite of the back-up papers for the *Depletion Study, supra,* showing data for the larger companies in the group whose data is used for gas costing. There were 17 companies in Industry Group 131 (p. 18). Of these, only five reported income tax before the foreign tax credit and only three reported tax after the foreign tax credit. The

composite liability for the group, not counting tax losses, was 2/10th of one percent of gross receipts. Data for 1962 (Exhibit C) shows a similar low composite rate of tax, with only 3 companies out of 20 reporting a tax (four before credits) and with a higher group net tax deficit than net income. When it is considered that some of the reported tax liability may be eliminated by losses in subsequent years,[37] and that approximately 45 percent of the reported *Depletion Study* gross receipts are from sources unrelated to production[38] which presumably bears an effective tax rate commensurate with other industries, it becomes clear that the typical independent producer will usually pay no tax on his production activities.

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We notice the data reported in the *Depletion Study*, in Exhibit 299-A and in the *Tax Stipulation*. However, we do so for the limited purpose of assuring ourselves that with regard to small producers we are justified in not specifying a federal income tax component in our rates. Direct evidence would have been preferable in deciding this issue. The data does not necessarily indicate that oil and gas producers would never pay a tax. We recognize that if a company has unusually high profits, if it earned large amounts of unrelated income, or if it restricted its exploration and development activities, it might show a tax liability for a

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[37] Internal Rev. Code of 1954, Section 172 (net operating loss carry-back).

[38] Page 44, column 17 of the Depletion Study shows $2,189,843,000 reported income from mineral properties and $4,008,872 total business receipts. The "131" companies for which income tax data are reported on the tax stipulation for 1962 have total gross receipts of $2,329,112,000, but a reported depletion of $184,189,000 indicating much greater amounts of unrelated income (p. 11).

particular year. But on the state of this record and with the other information available to us we hold that, absent more direct evidence to the contrary, we are justified in concluding that the oil and gas producer will typically have no tax as a result of his exploratory and production activities.

Upon consideration of the exhibits as part of the record, we find confirmation of our conclusion that on an industry-wide basis there is no support in the record for a finding of an income tax liability attaching to the industry's gas production operations. Again, some of the corporate and individual entities constituting the industry may in particular years pay income taxes. However, the tax component, like other cost components, must be considered in the context of the industry as a whole. The cost of individual companies are only significant as a part of the overall costs. In this context, the indications of income tax liability suggested by the producers herein, viewed in the light most favorable to them, point only to a *de minimis* impact on overall costs.

With respect to income taxes, in order to make a finding that the industry as a whole pays taxes, it is essential in the first instance that we have for analysis a reasonably representative group of income tax returns of the corporate and individual entities constituting the industry. The producers have not chosen to come forward with such a group of income tax returns for the record. Without such returns available to us, we cannot begin the required analysis which will establish the extent of the industry's tax liability, if any, in the light of the provisions in the revenue laws which would reduce or eliminate the tax liability. Obviously, evidence in the record indicating that some of the companies or individuals may pay a tax will not suffice. Such evidence does not support a finding that the industry

as a whole pays a tax on its gas production operations. Consequently, in view of the lack of record support, we are constrained to find no basis for a determination that a tax liability exists.

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PRODUCTION TAXES

In Opinion No. 468 the Commission stated:

> "We think that reasonable local taxes are a valid basis for a difference in ceiling prices between one area and another and if reasonable the tax applicable in each state should be applied to the gas produced in that state."

The tax imposed by the State of Louisiana is at the rate of 2.3 cents[39] on each Mcf severed from the ground in the area within its taxing jurisdiction. This tax rate is the highest tax on natural gas charged by any producing state, but we agree with the Examiner and with all parties that the full local tax should be included in the gas-well gas costing for all production where the tax is applicable. As the Commission held in *Permian*, "In the event of any increase in [production] taxes . . . the Commission will consider whether ceiling prices shall be increased and, if so, to what extent." (34 FPC at p. 206) We disagree with the Examiner, however, in two applications of the tax: First, in his summary of the cost of new gas-well gas the Examiner included only the working interest portion of the Louisiana tax as a cost to the producers with a full royalty at 14 percent being shown as paid to the royalty owners. We are advised, however, that as a matter of general practice

[39] La. Rev. Stat., Title 47, Sec. 633(9), (Supp. 1964). A severance tax of 1.3 cents per Mcf is applicable to low pressure (below 50 p.s.i.) and/or low volume (below 250 Mcf per day) wells but such volumes are not significant.

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the producer pays the full 2.3 cents per Mcf tax to the State and then transmits to the royalty owner the contractual amount reduced by the taxes chargeable to the royalty-holders interest. Although the practical effect is that of a complete "wash" (in that the tax cost component is increased by the precise amount of the reduction in the royalty allowance) we believe that the inclusion of taxes at the full amount is preferable as more accurately portraying the actual situation on the incurrence and payment of the tax.

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Our second area of disagreement is in the Examiner's failure to deduct the full amount of State tax for production occurring outside of the area of State jurisdiction. The production tax is applicable on gas produced in Louisiana in the areas subject to State jurisdiction and in those offshore areas which are concededly within the State's jurisdiction; the production tax may or may not be applicable in offshore areas which are in dispute between the State and the Federal Government.[40] The tax is not collected in the admitted Federal domain offshore, nor is there any separate Federal tax applicable in that area. Under these circumstances, we believe it improper to include any charge for State tax in those areas where no tax is charged or chargeable. The producers favor the fixing of a single ceiling price for gas produced in both the State and Federal

[40] See footnote 11 and cases cited. The present practice with regard to production from the disputed areas is that the State production tax is charged but the amounts thereof are placed in escrow pending resolution of the jurisdictional question. Under our order the producers will be allowed to continue this practice. The ceiling for production from the disputed area thus includes an allowance for State production taxes. But refunds will later be required to the extent that certain of this production is finally held to have been from the Federal domain.

domain, arguing that the absence of a tax cost component in the Federal area is offset by greater risk offshore or by the need to induce a greater exploratory effort through a higher than cost ceiling in the offshore areas. These are matters properly considered elsewhere. In this section we are concerned only with making an accurate unit cost determination. The inclusion of a phantom tax allowance where no tax is in fact charged cannot be regarded as acceptable.

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ROYALTIES

The Examiner determined that the national average royalty should be fixed at 14 percent based on producer witness Auten's determination of a 15.7 percent average royalty but adjusted downward by 1.7 percent to eliminate overriding royalty payments made by one producer to another. Although this is a change from the 12½ percent royalty allowance in the *Permian* case, we agree that the additional evidence submitted in this record, which was not available at the time of the earlier proceeding, permits a more precise computation.

A number of the producers have cited the reduction from 15.7 to 14 percent as error on the ground that any overstatement resulting from a failure to deduct intra-industry royalty receipts is relatively minimal. But as the Examiner pointed out, the 15.7 percent is inflated to begin with, because it includes pipeline royalties averaging about 25 percent of gross revenues, much of which is apparently paid to other producers. We affirm the Examiner's finding of 14 percent net royalty.

The Amerada group also contends that the average royalty burden in Southern Louisiana is higher than the national

average royalty. Even assuming the Southern Louisiana royalty to be higher, that is immaterial to our purpose here of determining the national royalty. Furthermore, considering all items except State production tax — royalty, drilling costs, etc. — the Examiner has shown that overall the Southern Louisiana new gas costs do not appear higher than the national average. We decline to isolate royalty. On this basis we accept the 14 percent figure as a sufficient allowance. On a unit basis the resulting allowance is 2.24 cents per Mcf, net of taxes.

PROCESSING FOR QUALITY DEFICIENCIES

The producers' cost of processing gas is about 2.4 cents per Mcf, assuming a 12 percent rate of return allowance and a Btu allocation of joint plant costs between liquids and gas.

As the producers point out, this averages out to 0.48 cents per Mcf when spread over total processed and unprocessed gas. About 69 percent, or 0.33 cents per Mcf of these costs relates to gathering, a matter covered below. The other 31 percent, or 0.15 cents per Mcf relates to quality improvement costs. In other words, on the average it costs the producers about 0.15 cents per Mcf to overcome the risk of finding low quality gas in the area. This 0.15 cents actually is a somewhat exaggerated amount because it includes a full 12 percent return allowance (see 34 FPC 1072), does not modify the Btu basis for allocation (see 34 FPC 400-405, 1072), and reflects plants operating in the test year at only about 70 percent of capacity. Whether viewed as a cost or a risk we believe that the 12 percent rate of return determined above amply covers this 0.15 cents or less of quality problem in the area. Or, reducing the return al-

lowance by 0.15 cents, the net rate of return would be approximately 11.75 percent or more, adequate for the risks of the industry in general and the special risks in the Southern Louisiana area.

We recognize the difficulties of plant cost allocations where liquids extraction is the primary purpose of the plant and processing is secondary, albeit beneficial to the gas. In Southern Louisiana, however, the cost analysis demonstrates that in any event the amount allocable to gas improvement must be very small.

AREA GATHERING

In the Permian Basin area gas-well gas is customarily sold to the pipelines at or near the wellhead. Accordingly, our cost analysis in that case did not provide anything for gathering beyond what was already reflected in the "other production facilities" cost component. (Casinghead gas, on the contrary, is generally gathered by the producers and sold to the pipelines at a plant tailgate in the Permian Basin area. However, the value of the residue gas was found no higher than the value of gas-well gas at the wellhead, so nothing extra was allowed for the producers' gathering of casinghead gas. 34 FPC 211, 358-359). In Southern Louisiana gas is customarily delivered to the pipeline at a central point in the field or at a tailgate of a plant. Therefore, the cost analysis and the ceilings we fix should allow for gathering. Since customs vary among areas in this regard,

the gathering allowances should be based on area considerations.

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The Examiner concluded that the producers incur 0.18 cents per Mcf for independent gathering systems in the area. In addition we have estimated above that producer plants account for another 0.33 cents for gathering in Southern Louisiana. There is a further possibility that the gathering costs reflected in the lease and related accounts (see "other producing facilities," above) would be higher per Mcf in Southern Louisiana than the national average. However, the Louisiana data are already part of the national data. Moreover, the gross investment data in Exhibit 29 shows, for example, that the U.S. and Southern Louisiana have about the same ratio of related producing facilities to drilling costs (IDC) for gas leases: 6.8 percent for the U:S. and 7.2 percent for Southern Louisiana. Thus nothing extra is warranted in this regard. In sum, the area gathering allowance should be about 0.18 plus 0.33 or 0.51 cents per Mcf — in addition to the amount already reflected in the general cost component "other producing facilities."

NATIONWIDE NEW GAS-WELL GAS COST

The following table sets out our computation of the national average cost of new gas subject to the Louisiana severance tax on the net investment rate base method. We have also included the Examiner's cost determination for comparison:

	Cost in Cents per MCF	
	Examiner	Commission
Exploration and Development Costs		
Dry Holes	1.42	1.42
Other Exploratory Costs	1.60	1.60
Adjustment for Exploration in Excess of Production	1.12	1.12
Production Operating Expense	2.65	2.70
Net Liquid Credit	(3.05)	(3.30)
Depletion, Depreciation and Amortization of Production Investment Costs		
Successful Well Costs	2.88	2.88
Lease Acquisition Costs	0.76	0.76
Other Production Facilities	0.40	0.40
Return on Production Investment	5.33	5.33
Return on Working Capital	0.34	0.35
Subtotal @ 14.65 psia	13.45	13.26
Subtotal @ 15.025 psia	13.79	13.60
Regulatory Expense	0.17	0.15
Royalty @ 14 Percent	2.59	2.24
Area Gathering	—	0.51
TOTAL — Federal Domain	16.55¢	16.50¢
Production Tax	1.98	2.30
TOTAL — Onshore and Offshore Within Louisiana Taxing Jurisdiction	18.53¢[41]	18.80¢

[41] The Examiner's ceiling of 19.5 cents per Mcf for new gas produced onshore is based on his computed cost of 18.53 cents rounded to 18.5) plus the addition of 1-cent per Mcf as an "incentive factor". His offshore ceiling of 18.0 cents reflects a reduction of only 1.5 cents of the State tax.

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FLOWING GAS COST

The Examiner discusses the issues dealing with the determination of the flowing gas cost. These issues involve, among others, whether to cost only flowing gas-well gas and whether to use that cost in establishing a single ceiling price to be applied to all gas other than new gas-well gas and residue gas derived therefrom; the use of an area historical cost-of-service; and whether the 1960 test year costs, as reported in the Appendix B and C responses, may justifiably be used in the determination of the flowing gas cost. The Examiner's discussion is reproduced in Appendix E to this Opinion. We are in full agreement with the Examiner on his resolution of these matters, and hereby adopt his findings in establishing the framework for the flowing gas cost determinations.

We specifically affirm the Examiner's costing only gas-lease gas and not casinghead gas or combination lease gas. Casinghead was, is, and will be a by-product of oil finding and production operations. It is therefore inappropriate to cost casinghead gas for our ratemaking purposes. Our modified Btu allocation of E&D costs happens to yield a cost for casinghead gas, but that incidental result seems merely mechanical to us. Any method which allocates substantial dry hole and geological costs to casinghead gas would seem mechanical to us. Likewise, there are no data now available that would eliminate this kind of problem from combination leases (productive of both oil reservoirs and gas reservoirs).

We also affirm the Examiner's use of national E&D data and area productive lease data for determining flowing gas costs. See our discussion of this matter under New Gas Cost, above.

The Examiner rejected the suggestion that the new gas ceiling price apply to new casinghead gas and residue gas derived therefrom. The State of Louisiana and the Amerada group argue in their exceptions that the Examiner has under-estimated the extent to which the supply of casinghead gas is responsive to price and, secondly, that one of the incentive functions which the new gas price is to perform is to induce

the commitment of new gas reserves to the interstate rather than the intrastate market, and that this consideration is equally applicable to both casinghead and non-associated gas.

We decided in *Permian* and decide again here not to have the ceiling for new gas-well gas apply to casinghead gas of any vintage. Our decision is directly related to our findings on the industry's recently developed ability to conduct a directional search for gas-well gas. Casinghead gas is discovered as a result of the search for oil. For this reason the search for casinghead gas cannot be encouraged to any significant extent via the mechanism of a higher price applicable thereto. Although the exceptions warn of excessive flaring, creation of conservation problems, and the premature abandonment of reserves, no substantial evidence to this effect has been presented and the arguments, standing alone, do not persuade us that suitable and sufficient quantities of casinghead gas will not continue to find their way into the interstate market at the flowing gas ceiling determined here. In short, we find no justification for allowing casinghead gas the higher ceiling applicable to new non-associated gas.

The Examiner rightly relied on respondent composite

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data to determine the cost of flowing gas. Various producers continue to press their objections to the use of composite respondent data. Hunt and others argue that accounting and reporting differences among the respondents preclude any compositing of the respondent data. We affirm the Examiner's rejection of these arguments. Previously, we issued an interlocutory order upholding the Examiner's denial of an untimely Hunt motion to subpoena evidence, etc. to attempt to impeach the compositing of the data. 32 FPC 1160. Our order upholding the Examiner, however, was without prejudice to Hunt's right to argue the weight of this data. We are not convinced by Hunt's arguments against the data. The allegations about differences in depreciation methods and in lease classifications do not materially detract from the weight of the data. None of the different depreciation methods appears to understate depreciation costs, nor does it appear that classification of certain cycling operations into oil lease categories causes any understatement of costs. The errors alleged by Hunt in the reporting of volume data would, if anything, favor the producers by exaggerating the unit cost of gas; correction of the volume would lower the unit cost of gas

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slightly. We find no error prejudicial to the producers or the consumers in the compositing of respondent data.

Respondents also attack the composited data as unrepresentative for failure to include enough small producer data. The composite does include some small producer data from questionnaire Appendix C.[42] Altogether the composite accounts for 85-90 percent of hydrocarbon production in the

[42] In *Permian*, we excluded Appendix C data while noting that inclusion or exclusion made no material difference to the determined average cost.

area. With regard to the remaining 10-15 percent, some small producers simply do not maintain records to provide data for compositing; some of the remaining production relates to non-operating small producer interests whose production costs would be substantially the same as their operators who did in fact report data; the other part of the unreported production data could not be expected to alter (up or down) the average production cost of the bulk of the area gas represented by the composite.

As for national E&D costs and operations, the composite accounts for about 50 per cent of national production and commensurately also accounts for about 50 percent of national dry hole costs in the test year; the industrywide dry hole costs amounted to about $8.60 per foot drilled (34 FPC at 291) for about 77.4 million dry feet drilled or between $650 and $700 million; the composite covers almost $350 million in dry hole drilling costs and contributions (Exhibit 29 Revised). Of course the major companies, who dominate the respondent composite, account for the preponderance of national lease costs. Thus, the composite's share of E&D costs matches or exceeds its 50 percent share of production. Composite unit cost experience would therefore be substantially representative.

EXPLORATION AND DEVELOPMENT COSTS

Producers are concerned with the replacement of oil and gas that they produce and sell. As part of their annual expenditures, they incur costs relating to unsuccessful exploration and development activities, including both outright failures and activities whose outcome at any particu-

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lar time is yet uncertain.[43] If the efforts to which these costs are related had been successful, they would have resulted in the production of gas or liquids, and such costs would have then been assigned directly to the relevant identifiable production account. Since the efforts were unsuccessful, the costs are undifferentiated and must therefore be allocated among the various lease products on some equitable basis. The purpose of the allocation of these joint exploration costs is to require each lease product "to bear its proper share of the joint costs in light of all of the circumstances that affect the incurrence of joint costs." *Phillips Petroleum Company*, 24 FPC 537, 556.

We have previously considered and rejected the claim of The California Company that exploration costs should be computed on an area basis. We do not consider it necessary to address ourselves further to its contention at this point. We adhere to the conclusion that the E&D allowance for flowing gas should be computed on a nationwide basis.

The problems created by the need for an equitable allocation of E&D costs were thoroughly dealt with in *Phillips*, 24 FPC 537, 555-62.[44] In that case the Commission adopted

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the modified Btu method to allocate all of Phillips' E&D

[43] These costs include, *inter alia*, exploratory and development dry hole costs; geological and geophysical expenses; cancelled, surrendered and abandoned leases; amortization of non-productive acreage; lease rentals and options, as well as a return allowance on the E&D rate base, consisting in the main of the remaining or net investment portion of the acquisition cost of untested acreage. The normal practice in the industry is to charge off E&D costs (apart from lease acquisition costs) at the time of incurrence. See *Permian*, 34 FPC 193-194.

[44] See also Examiner's decision, 24 FPC 590, 633-679.

costs. The method has the advantage of amalgamating the important factors which influence the incurrence of these costs: demand for the respective lease products, their relative costs, relative values and primary use. While the Commission noted that it is the Btu content of fuels which make them useful to consumers, it also noted that physical energy content

> ". . . reflects only in part the potentialities of the hydrocarbon products. Oil and gas are not produced, purchased and used merely on the basis of Btu content or available energy. The transportation, refining, distribution and utilization factors are equal to or greater than the factors of exploration and development. As the examiner explains, the chief function of the oil industry is to provide fuel for transportation. Oil and its component, gasoline, are basically useful because they provide energy in compact, mobile and easily controlled liquid form. Actually, the heavier the crude oil, the higher will be its Btu content but the lower will be its gasoline content and its price. Gas, on the other hand, does not have the mobility of oil, for it must be carried in pipelines under pressure and used under limited conditions. Both oil and gas are used for the manufacture of chemicals and plastics which could not be properly compared on the basis of Btu." (24 FPC at 556-557).

The value relationship between oil and gas is reflected in the modifying factor. By multiplying each liquid Btu by the determined factor, E&D costs are divided between oil and gas in such a way as to reflect their respective values.

Employment of the modified Btu method in allocating joint E&D costs is supported not only by *Phillips* and the *Permian* opinion, but by other Commission precedents. See *Continental Oil Co.*, 27 FPC 96, 104 (1962); *Hunt Oil Co.*, 28 FPC 623, 624 (1962); *H. L. Hunt*, 28 FPC 897, 901 (1962).

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The staff in this proceeding proposed the use of the modified Btu method with an economic factor of 3.5 The

method allocates the producers' nationwide 1960 E&D costs among the various lease products produced in 1960 on the basis of modifying the actual Btu content of the lease products by 3.5 for lease liquids and 1.0 for gas. The evidence for 1960 gas and lease liquids production shows that a barrel of liquids has about 5.1 times the Btu content of a Mcf of gas. The price ratio between the average barrel and average Mcf of 1960 production is about 20.4. Divided by the 5.1, that indicates an economic factor of 4.0. The staff also computed a factor of 4.09 from the relative price and Btu content of lease liquids and gas for 1960 from the questionnaire responses (Exh. 26, p. 3, 5). Also, the relative production cost between the oil only and gas only leases for the respondents in 1960 on a continental basis, divided by the Btu ratio, indicated an economic factor of 4.03 based on cost rather than price.

The appropriate economic factor for these allocations is 3.5. This factor allocates more costs to gas and less to liquids than the factor of 4.0. We think this is appropriate in light of the continuing shift from oil drilling toward gas drilling. The 3.5 is also consistent with a national new gas ceiling of about 16.5 cents per Mcf. The Examiner instead used a factor of 3.35, based on the ratio of $2.90 per barrel and a national new gas ceiling of about 17.01 cents per Mcf, divided by the Btu relationship. While this difference in factors seems small, we cannot agree with the use of 17.01 rather than 16.5 cents as the national average new gas ceiling. Our discussion of new gas costs demonstrates that some changes from Opinion No. 468 are warranted for cer-

tain new gas cost components: royalty, overheads, etc. But it does not appear from this proceeding that overall the 16.5 cents figure determine in *Permian* is now too low.

The Examiner has discussed in his initial decision the Amerada group's proposal for allocating certain developmental dry hole costs on the basis of a direct identification of such expenditures to basic reservoir type (oil or gas) made by a number of the producers accounting for about 83 percent of the composite developmental dry hole costs. The identifications

were reported on a separate questionnaire.[45] In *Permian* the Commission considered this method and concluded that the attempted allocation or developmental dry holes on the basis of reports of well drilling intentions by producers was defective in that it involved "subjective considerations." The Commission also found that the "data obtained are not the result of a random sample of all producers on an objective basis and do not offer a reliable foundation for fixing prices." The fact that the data in this proceeding was developed at the request of the Examiner, as against the method in *Permian* of a voluntary polling, works to mitigate one of the major objections to the direct assignment method.

However, we remain in doubt about this kind of data. Some producers have not reported it. Furthermore, we note that exploratory dry holes have not been assigned. Since over $32 million in dry holes could not even be seg-

[45] This prior allocation was at first supported by AGD. This support has since been withdrawn. AGD states that it now agrees with the Examiner's treatment of development dry hole costs as a part of exploration expense. AGD Brief Opposing Exceptions, p. 93.

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gregated into "developmental" and "exploratory", we conclude that at least some of the so-called developmental drilling cannot be reliably identified to gas or oil. While the identified dry hole data should not be used directly as proposed by the producers, its general significance does further convince us that the economic factor should be 3.5 rather than 4.0.

Finally, the producers urge that the successful efforts method found appropriate for new gas should also be used in allocating flowing gas E&D costs. For new gas we first related both successful drilling and dry holes to reserves found. Then we adjusted the E&D amounts to reflect the fact that E&D would be recovered over current production. The producers have not presented their reserve data and have resisted any efforts to solicit that data. We therefore lack an adequate basis for making the successful efforts calculations.

In conclusion, the E&D costs should be allocated according to the modified Btu method using an economic factor of 3.5. The result is an E&D allowance of 4.17 cents per Mcf including return. See Appendix F.

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PRODUCTION COSTS

Production costs consist of direct and indirect lease expenses, current provision for DD&A (depreciation, depletion, and amortization), and overhead and other production expenses. In addition, a return is allowed on the net production investment rate base including a working capital allowance. For convenience the lease, overhead, and other production expenses are grouped as a single Production Operating Expense item. We will therefore consider pro-

duction cost in terms of Production Operating Expense, DD&A, and Return.

There are three major steps in determining production costs. The first involves compositing the cost and volume data for each lease category,[46] as reported by the respondent companies in response to the Commission's cost questionnaire. The second step is to prepare a cost of service. The third step is to allocate the joint product lease costs between lease gas and lease liquids in order to determine the unit production costs for gas.

There is relatively little controversy concerning the mechanics of compositing the cost and volume data by lease type. However, since we are basing our cost analysis of flowing gas well gas on the staff's composite cost of service for St Appendix B and C companies, we will review certain adjustments which the staff made in using the composited data to prepare a cost of service.

When the respondent companies reported common costs, such as overhead investment, overhead expense, and materials, supplies, and prepayments by functions (such as Production and E&D), their assignment was accepted. Otherwise, staff made the assignment to function. Staff also assigned production overhead investment and expense and materials, supplies,

and prepayments to the various lease classifications where the respondent companies did not do so. It allocated production overhead investment and materials and supplies on

[46] There are six lease classifications, as follows: (1) oil only; (2) oil casinghead; (3) gas only; (4) gas condensate with lease separation; (5) gas condensate without lease separation; and (6) combination.

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the basis of gross lease production investment, and allocated production overhead expenses and prepayments on the basis of direct and indirect lease expenses exclusive of DD&A. These allocations are consistent with our prior determination of this issue in Opinion No. 468 (34 FPC 296,297) and are approved for the reasons there given.

Staff included in its composite certain separately reported production payment volumes. This adjustment was necessary in order to match total costs with total volumes produced and is approved.

In the seven instances where a company did not report Related Producing Facilities by lease category, staff made the allocation on the basis of net lease investment. This method of allocation is consistent with the questionnaire instructions applicable to the Related Facilities item and is proper in the interest of obtaining comparability of data.

Staff converted certain minor volumes of liquids to gas on gas condensate without lease separation leases, based on conversion factors provided by the respondents involved. These liquids were not separated at the lease level, but at plants located beyond the lease. It was therefore proper to convert them to equivalent raw gas volumes, in conformity with the questionnaire instructions.

Another preliminary question is whether reinjected volumes should be used in calculating production costs. Respondents concede total produced volumes are appropriately used in computing production operating expense, but contend these volumes should be reduced by the volumes of reinjected gas for purposes of determining DD&A and return. We do not agree. Cycling leases contain investment in additional equipment, such as injection wells and field compressors, with their attendant operating costs which are not incurred on non-cycling leases. Cycling is perform-

ed in order to enhance the recovery of liquids. Therefore all lease costs, expenses and investment, relate to a greater or lesser degree to the liquids

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which would not otherwise be recovered, or in part would be available at a later stage of reservoir depletion. We here reaffirm the concept that total volumes should be used, rather than sales volumes, for computing operating expense, DD&A and return. This assures that liquids bear their fair share of total costs. *H. L. Hunt, et al.*, 28 FPC 897 (1962); *Permian*, 34 FPC 297-298 (1965).

Coming now to the allocation of costs between gas and the liquids contained in the gas, we note that of the three gas lease categories to be used for costing purposes, only one, gas condensate with lease separation, requires allocation. No allocation is required for the gas only and gas condensate without lease separation leases, since these leases do not produce liquids at the lease level.

Several methods have been proposed by which to make the required allocations. Respondents propose the vapor volume method of allocation. This method is posited on the fact that one barrel of condensate vaporized to approximately 1.123 Mcf of gas. Respondents use this conversion ratio of 1.123 to 1 to allocate joint product costs between condensate and gas respectively, even though a barrel of condensate, which leaves the lease as a separate product, brings approximately 20 times the price of an Mcf of gas. Such an allocation is consistent neither with economic reality nor with the known cost of producing liquid hydrocarbons in the absence of gas, and must be rejected. *Hunt Oil Co.*, 28 FPC 623, 624, note 1 (1962); *Continental Oil Co.*, 27 FPC 96, 104 (1962); *H. L. Hunt, et al.*, 28 FPC 897 (1962).

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In determining production costs for flowing gas-well gas we will use the relative cost method to allocate costs between condensate and gas on the gas condensate with lease separation leases. This is the method of allocation we have consistently used throughout the course of regulation in producer rate cases. *Phillips Petroleum Co.*, 24 FPC 537 (1960), affirmed 373 U.S. 294 (1963); *Hunt Oil Co., et al.*, 28 FPC 623, 624 (1962); *Permian*, 34 FPC 159, 215 (1965). It is logical and realistic in concept, and can be applied in a relatively simple and workable manner.

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The rationale of the relative cost method is that the joint costs relating to production of both gas and condensate should be allocated between these co-products on the basis of the costs of the separate production of liquid hydrocarbons relative to the separate production costs of gas.

The cost of separately producing liquids and gas involves a determination of the cost per barrel of commercial lease liquids from oil only leases (the oil leg), and the cost per Mcf of gas on gas only leases (the gas leg). The unit cost of liquids is then divided by the unit cost of gas. The result of this division is termed the relative cost ratio, since it provides the unit cost of lease liquids relative to the unit cost of lease gas. The liquid element of this ratio is then multiplied by total condensate production from gas condensate lease separation leases, and the gas element of the ratio is multiplied by total gas production volumes from the same lease category. Thus, where the relative cost ratio is 20 to 1 and the leases in question produce one barrel of condensate per 80 Mcf of gas, the costs would be allocated 20 percent to condensate

and 80 percent to gas. Separate allocations are made for each of the three components of production costs, *i.e.*, Production Operating Expense, DD&A and Return.

There are several areas of controversy between the parties relating to the relative cost method and its application in this proceeding. The first is whether the oil and gas legs should be developed on an area basis or on a national basis, and the related question of which lease categories should be used. Both AGD and the staff recommend national single product legs. Respondents urge area legs, with the oil leg developed from oil only lease data, and the gas leg developed from gas only leases plus gas condensate without lease separation leases (exclusive of cycling leases).

No party recommends area legs based on oil only and gas only lease data, since production from the area gas only leases accounted for less than 1 percent of total 1960 Southern Louisiana area gas-well gas production as reported by the 81 companies included in the staff composite. Obviously,

the area gas only leg is too thin. However, we do not think the area gas leg is made acceptable by adding the gas condensate without lease separation leases. Even when so developed the leg contains less than 5 percent of reported 1960 area gas-well gas production for the 81 companies. If cycling leases are excluded, this is reduced to approximately 3 percent. In addition, the leg combining gas only leases and gas condensate without lease separation leases is subject to the disproportionate influence of four unusual leases in the gas only category. The four leases accounted for approximately 30 percent of the area gas only produc-

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tion as reported by the entire 81 company group, and reflect unit costs in excess of one dollar per Mcf. More importantly, inclusion of the gas condensate without lease separation leases is inconsistent with the very principle of the relative cost method, by which allocation is made on the basis of the separately identified unit cost of producing liquids in the absence of gas and gas in the absence of liquids.

On the other hand, national legs provide a broad basis for determining the relative cost of separately producing lease liquids and separately producing gas. There is no question that the nationwide cost and volume data for the 81 company group are the most comprehensive available on a cost, volume, and geographical basis, and we think they are representative of national oil only and gas only production cost experience. The question is whether the national ratios are proper for use in deriving area costs. In this connection it must be remembered that in determining the cost of flowing gas-well gas we have decided to use area costs and area production volumes. The allocation ratios involve only the apportioning of reported area costs between gas and condensate. We think the use of national ratios for this purpose is fully warranted, especially where the available data do not permit development of reliable area ratios. 34 FPC 298-300.

Respondents argue that the national gas only leg is heavily influenced by production from the Hugoton-Anadarko area, and that the costs of production in that area are not representative of the production costs on gas only leases in Southern Louisiana. However, under the relative cost method the cost of producing gas from the natjonal gas only

leases is not applied or imputed directly to the gas produced on the gas condensate with lease separation leases in Southern Louisiana and neither is the oil leg unit cost used in this manner. It is merely the gas only and oil only cost relationship that is sought. It is this ratio which is then applied to the allocation of Southern Louisiana joint production costs. We believe the total nationwide costs of the 81 company group operating in Southern Louisiana, including all oil only and all gas only production, is the proper one for deriving the allocation ratios under the circumstances of this case. As for the Hugoton-Anadarko gas being old and relatively shallow, the evidence also shows that the national oil only leg likewise reflects older and shallow production. The legs appear commensurate in these regards.

Respondents' argument for the elimination of the Hugoton-Anadarko gas only production is not new. The identical issue was raised in the *Phillips* case and rejected by the Commission when it stated, "As the Examiner states, the relative cost method is particularly suitable for allocating the joint production costs of a company such as Phillips where the number of leases and geographical spread of operations provide a broad base for determining the unit costs of the separate products exclusive of exploration."[47] The same reasoning, leading to the same conclusion, is appropriate here.

In our opinion a gas leg containing Respondents' costs of production in all geographical regions of the continental United States, including the Southern Louisiana area, provides representative, stable cost ratios, expressing the re-

[47] 24 FPC at p. 553.

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lationship between the average cost of producing a barrel of lease liquids with virtually no gas and an Mcf of gas with virtually no liquids. Our conclusion is that the national single product ratios developed by the staff provide the best basis for the allocation of Southern Louisiana joint production costs.

Another problem relating to the relative cost method of allocation concerns shut-in leases. Both staff and AGD

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did not add in shut-in leases in developing the oil and gas legs. Respondents object to this adjustment, but urge that if shut-in lease costs are not included, neither should costs related to shut-in wells on producing leases be included when determining the ratios. Their argument is based on the fact that there are proportionately more shut-in wells on producing oil only leases than there are shut-in wells on producing gas only leases. If the shut-in wells on producing leases are excluded, the effect is to reduce the unit cost on the oil only leases and thereby reduce the share of joint costs allocated to liquids and increase the costs allocated to gas.

First, as to the exclusion of shut-in leases, we believe this is proper and necessary. It seems clear that the inclusion of shut-in leases would introduce a distortion into the calculation of relative production costs since there is no production involved. There being no production, there can be no unit production costs for shut-in leases. Their inclusion would have the effect of burdening producing leases with the costs related to shut-in leases, and would exaggerate the unit production costs on the productive leases. We have previously considered this issue and uniformly held that shut-in leases should be excluded in developing the

allocation ratios. *Hunt Oil Co., et al.*, 28 FPC 623, 624 (1962); *Permian*, 34 FPC 300.

This exclusion is applicable only in determining the proper allocation ratios. In calculating the unit cost of gas, the reported costs of shut-in gas leases are included in the total joint production costs allocable to gas or single product production costs directly assignable to gas.

The exclusion of shut-in wells on producing properties stands on a different footing. The leases involved are on production, and the costs relating to shut-in wells thereon are a necessary and unavoidable incident to production. The productive lease should bear the cost of its shut-in wells. The fact that there are proportionately more shut-in oil wells is to be expected in view of State production restrictions and other considerations. But the shut-in well cost in such instances is a direct and legitimate cost of production

for that lease. We therefore reject the exclusion of shut-in wells on producing leases.

Another question relates to whether return should be allocated on the basis of gross or net investment. The total return on the gas condensate with lease separation lease category must be allocated between gas and condensate. This total return is computed on the basis of a net production investment rate base. But to allocate return on a net investment basis would have the effect of allowing proportionately more return to gas relative to condensate. This is so because oil only leases are more depleted than gas only leases, and therefore the remaining net investment in oil only leases is relatively smaller than in gas leases. However, condensate and gas are produced together on the gas con-

densate with lease separation leases and DD&A is charged to the lease as a unit. Therefore, it would be improper to allocate return on a net investment basis; the result would not conform to the operating realities of joint production. We conclude that the allocation of return should be based upon gross investment ratios for oil only and gas only leases. 34 FPC 300-301.

Calculated according to the methods outlined above, Production Operating Expense is 1.93 cents per Mcf, DD&A is 3.19 cents per Mcf, and Return (at the 12 percent rate herein determined appropriate) is 5.71 cents per Mcf, for a total production cost of 10.83 cents per Mcf.

RATE OF RETURN

In Opinion No. 468 the Commission adopted a rate of return of 12 percent for flowing gas-well gas. However, it distinguished the factors going to make up the return on the ground that unlike new gas, flowing gas was found largely in an undifferentiated search for hydrocarbons and thus had a lesser degree of risk incident to its finding. Offsetting this was the fact that much of the flowing gas in the Permian Basin was below pipeline quality and thus would not command the ceiling price. As added considerations the decision noted that flowing gas revenues are used

in the continuing exploration process and that the price for flowing gas may have some effect on the commitment of casinghead gas to the interstate market.

The Examiner likewise found in this case that the bulk of flowing gas in Southern Louisiana was discovered as an incident to the search for oil. While he agreed with staff and the distributors that the risk of low quality gas "does

not apply with similar force" to this area, he held that this situation was "counterbalanced by the peculiar importance of the Southern Louisiana area as a source of gas supply . . . so that the element of incentive assumes relatively greater importance . . ." Considering this factor together with the others referred to by the Commission, he concluded that the same rate of return should be allowed for flowing gas as for new gas.

We agree with the determination that the rate of return for flowing gas should be 12 percent. Revenues from sales of gas under contracts dated prior to 1961 continue to constitute a large portion of the total revenues derived by producers from gas sales in Southern Louisiana. The Commission desires to encourage the exploration for and development of new gas supplies. The funds to support these activities come from all gas sales; and are not restricted solely to a reinvestment of a portion of the revenues from the sale of new-gas well gas.

The Examiner also has referred to the fact that the flowing gas category includes new accretions of casinghead gas and residue derived therefrom and that the price allowed may determine its commitment to the interstate market. Since any casinghead gas already dedicated to the interstate market remains committed thereto, this factor could affect only future dedications. As pointed out by staff, other considerations may have as great or even greater impact upon the decision whether to dedicate new accretions of casinghead gas to the interstate market. These include the level of exploratory activity for oil, a possible change in the oil allowables by the State Commission,[48] and demands by the

[48] See *Texaco, Inc.*, Docket No. CI68-132, Notice of Application 8/9/67, temporary authorization granted 8/14/67.

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Louisiana intrastate market for gas.[49] However, the record does not provide a reliable measure for determining the extent to which these considerations could affect new dedications. Finally, we note that certain special risks occur in this area, risks common to both new and old gas: the risks of operating in a hurricane zone, drilling in heavily faulted geology and drilling in marshland and offshore waters. Accordingly, in view of the factors herein mentioned and other considerations in our previous discussion of rate of return, we shall allow a 12 percent return on flowing gas.

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PLANT LIQUID CREDIT

In determining the cost of flowing gas, we use Respondents' reported gas production volumes. These volumes are on a wet basis; that is, they include some Mcf of extractable liquids that are later removed in processing plants. By spreading the producers' costs over pre-extraction volumes we in effect require the plant liquids and the remaining gas to share in the costs of finding and production. By comparison, for costing new gas we rely on American Gas Association data, which are reported on a dry basis; that is, they *exclude* extractable costs over gas volumes because that would fail to attribute any of the costs to plant liquids found and produced with the gas. For new gas, we therefore credit the finding and production costs with the producers' share of plant liquid revenues. It would not be

[49] Since 1956 the Louisiana intrastate market has consumed approximately 20 percent of the net production for market as reported by the State of Louisiana Department of Conservation.

proper, however, to apply a similar credit to flowing gas; such a credit would double count the allocation of costs to entrained liquids, already accomplished through use of Respondent production volumes.

INCOME TAXES

In our discussion of new gas costs, we explained the reasons for denying an income tax allowance. The same reasons cause us to deny an income tax allowance in the cost of flowing gas.

REGULATORY EXPENSE

In our new gas cost determination we calculated regulatory expense as 0.15 cents per Mcf, before related royalty considerations. For flowing gas costs, which are stated inclusive of related royalty amounts, the regulatory expense becomes 0.17 cents.

PRODUCTION TAXES

As with our new gas cost determination, the appropriate production tax allowance is 2.3 cents per Mcf for gas subject

to Louisiana production taxes. No Federal domain gas production tax allowance is appropriate.

GATHERING COSTS

The Examiner found that 0.18 cents per Mcf should be allowed for certain gathering systems that had not been reported in lease or related accounts. As we explained in our discussion of new gas, the producers also incur additional gathering costs in their plant operations; these costs average out to about 0.33 cents per Mcf for the area, or a total of 0.51 cents per Mcf at 12 percent rate of return.

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SUMMARY OF FLOWING GAS COST

	Examiner	Commission
Production Costs		
Cash Expense	1.93¢	1.93¢
D.D. and A.	3.19	3.19
Return Allowance	5.71	5.71
E. and D. Expenses and Return	4.31	4.17
Subtotal @ 14.65 psia	15.14	15.00
Subtotal @ 15.025 psia	15.53	15.38
Regulatory Expense	0.17	0.17
Area Gathering	0.18	0.51
TOTAL — Federal Domain	15.88¢[50]	16.06¢
Production Tax	2.30	2.30
TOTAL — Onshore and Offshore Within Louisiana Taxing Jurisdiction	18.18¢	18.36¢

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PRICE ADJUSTMENTS TO REFLECT QUALITY DIFFERENTIALS

The reasons for establishing quality standards to define pipeline quality gas, and for requiring deductions from the ceilings for gas not meeting that quality, were set out in Opinion 468 (34 FPC at p. 221). As was there stated:

[50] The Examiner allowed an offshore price of 16.75 cents per Mcf, 0.87 cents higher than his computed cost for Federal domain production, of which 0.80 cents reflects his deduction of less than the full amount of the State tax.

"The importance of quality standards as an integral part of our ceiling price becomes readily apparent if it is recognized that gas is purchased for its energy. The price of gas cannot be related to volume alone but must be related to units of energy free of impurities and sufficiently compressed to enter the pipeline if it is to serve as a mechanism to assure just and reasonable rates."

and further:

". . . a producer receiving the ceiling price for inferior quality gas would be piercing the ceiling prices, insofar as the consuming public is concerned, just as much as if the producer were collecting an above-ceiling price for pipeline quality gas or deliberately diluting the gas with inert material."

Existing Contracts

We agree with the Examiner, for the reasons stated in his decision, that quality standards and quality deficiency price adjustments are unnecessary for gas flowing under existing contracts. The only exception to this otherwise blanket quality approval is for Btu content, which as hereinafter specified will be applicable to all gas. We also agree that quality standards are appropriate for gas sold under future contracts in order to assure that the gas supply which is contracted hereafter continues to at least meet the same minimum quality standards as gas presently flowing if it is to receive the area rate. Amerada's exceptions, and the exceptions of the Pipeline Group, against the issuance of any

quality standards are a restatement of arguments made in the briefs and rejected in the initial decision. Contrary to these exceptions, we believe that the specification of

minimum quality standards applicable to gas sold in the future not only provides important protection for the consumer but is required under a rate system which operates to set ceiling prices for gas meeting basic gas standards while still leaving the parties with substantial bargaining freedom to require standards in their individual contracts either more or less exacting than those here imposed. The standards here required are pricing standards only and will not operate to change the contractual provisions.

In declining to specify quality standards for gas under existing contracts, we are relying both on the existing contractual limitations and on the fact, as developed in the record, that certain of the more usual forms of impurities are not a problem in the gas produced in Southern Louisiana.[51] The decision not to include a water content limitation, however, stands on a somewhat different footing. The production of gas with a water content in excess of the prevailing limits of acceptability is a common occurrence nationwide. In Southern Louisiana such excess water is normally removed by the producer either at the wellhead or at a central field point in the process of recovering liquid condensate and dehydrated gas is delivered to the pipelines. Although the pipelines generally have the option of refusing gas having excess water content, they are not required to do so and circumstances may arise in the future where a pipeline will exercise the option to receive undehydrated gas and then incur the costs of dehydration in order to bring the gas up to pipeline quality without reimbursement from producers. Should this prove in the future to be a problem to the extent that it becomes a method for piercing the area ceiling, the decision against including a specific limitation applicable to flowing gas will be reexamined.

[51] Tr. Vol. 19, pp. 16,883-16,886; Vol. 20, p. 17,044.

Future Contracts

As in *Permian*, the first step in establishing price variations for quality is to determine the standards which

must be met if the gas is to receive the ceiling price. We consider each specification in turn:

Hydrogen Sulphide and Total Sulphur

The Examiner accepted staff's recommendation, based on the prevailing limits of acceptability, that the gas should contain no more than 10 grains of hydrogen sulphide and no more than 200 grains of total sulphur per Mcf. No specific exception has been noted and this specification is adopted.

Water Content

Staff's brief shows that 48 percent of the contracts, accounting for 55 percent of the 1963 sales volumes, specified a maximum water content of 7 lb. per MMcf while 46 percent of the contracts, accounting for 43 percent of the volumes, had a more stringent requirement of 6 lb. per MMcf. The Examiner accepted Staff's recommendation that 7 lb. per MMcf is a reasonable area minimum standard, rejecting the Pipeline Group's suggestion of the lower figure. The 7 lb. standard appears to be slightly more prevalent and will be adopted for the purposes of this area proceeding. However, as noted above, this in no way precludes the pipeline companies from requiring a more rigorous standard as a condition of the purchase contract.

Carbon Dioxide

The Examiner accepted Staff's finding that the generally prevailing area standard is that the gas shall not contain

more than 3 percent carbon dioxide by volume. We agree with this standard which, as is true of the other standards, will be applicable to the actual condition at delivery and not to the contract provision. As we determined in Opinion 468, a producer with gas containing more than 3 percent CO_2 by volume may be paid either on the basis of the volume of gas remaining after deduction of the acceptable volume of CO_2 or, alternatively, the producer may have his gas priced on the basis of the volume delivered to the pipeline which includes the excess CO_2 provided the Btu content of the gas is also measured at that point. "Under either alternative the pipelines' cost of processing actually incurred to

remove the carbon dioxide should be deducted from the area base rate to determine the applicable ceiling price. If the producer prefers to price his gas on the basis of the volume remaining after the carbon dioxide is removed, the Btu content for purposes of the adjustment provided herein shall be measured on the basis of the volume of gas after such removal and the total amount to be paid for gas should also be computed on the volume of gas remaining after the carbon dioxide has been removed."[52]

Other Impurities

The Examiner included a generalized requirement, common to gas purchase contracts, which provides that the gas is to be commercially free of oxygen, nitrogen, dust, dirt, gum-forming constituents, crude oil, liquid hydrocarbons and other substances which may cause transmission difficulties. We agree that any such impurities will be considered excessive, and will require a reduction in price, if

[52] Opinion 468-A, 34 FPC 1071 (1965).

they are present in sufficient amounts that a pipeline incurs processing costs to remove them. The amount of any reduction should equal the per Mcf cost of removal.

Delivery Pressure

The specification adopted by the Examiner provides that the gas is to be delivered at a pressure sufficient to enter the buyer's pipeline except that a minimum of 800 p.s.i. is to be available at the point of delivery. Staff's tabulation (Initial Brief, p. 267) shows that 88.3 percent of the 1960 volumes were delivered at pressures of 800 p.s.i. or more and that 65 percent were at or above 900 p.s.i.[53] The Pipeline Group excepts to the Examiner's specification of 800 p.s.i. as the minimum available delivery pressure on the ground that delivery pressures of 1,000 p.s.i. or more have been contracted for by the pipelines in 98 percent of their Southern Louisiana contracts covering 98 percent of the 1963 sales. The pipelines contend that the contract level is the

appropriate level, that the data is incomplete and that the fact that the gas delivered at particular pressures does not establish that the producers could not have delivered at higher pressures, had it been required by the pipeline companies at the time.

We have considered these arguments and find them unpersuasive. The Examiner's specification is reasonable as a minimum standard for computing the ceiling price applicable to particular gas. The standard provides that, to be eligible to receive the ceiling rate, the gas must be delivered

[53] For 1961 sales volumes, the figures were also identical; 89 percent at or above 800 p.s.i. and 66 percent at or above 900 p.s.i.

at a pressure sufficient to enter the buyers' line except that a minimum of 800 p.s.i. must be available at the point of delivery. The clarification to this standard spelled out by the Examiner to the effect that a producer with 800 p.s.i. available will be entitled to the area rate without penalty even if the pipeline buyer requires a higher (or lower) delivery pressure is likewise reasonable and will be adopted.

Consistent with our determination of quality standards as minimum requirements for entitlement to area rates, it is relevant to note that while the price to be paid for particular gas may not exceed the applicable ceiling price, it may be lower if the contract so provides. In determining the contract price, the standards and adjustments set forth in the contract should be used, and not the standards which are provided in the Order herein for use in calculating the applicable ceiling price.

Delivery Point

In his decision the Examiner determined that the matter of delivery point should be left for negotiation between the parties. He took this position in the belief that the nationwide new gas-well gas cost is a wellhead cost and does not reflect any gathering by producers beyond the wellhead. We do not accept the Examiner's disposition of this issue.

With regard to new gas-well gas, gathering costs are reflected in Other Production Facilities. This item is composed of lease equipment and off-lease investment, measured as a percent of successful well costs. As determined herein, lease equipment is 5.82 percent of successful well costs and

off-lease investment is 8.14 percent of successful well cost, for a total of 13.96 percent. Included in the calculation of off-lease investment is over $453 million in Related Producing Facilities for all lease types, as reported on Schedule D by 41 Appendix B respondents on a continental United States basis. The questionnaire instructions dealing with Related Producing Facilities stated in pertinent part:

> "Related producing facilities should include those facilities *beyond the lease* directly related to lease production operations, the costs of which are ordinarily included in determining lifting cost, such as lease water production and injection facilities, salt water disposal facilities, *lease gas gathering lines not part of gasoline or cycling plants*, camp buildings, etc." (Emphasis added)

These same cost elements, lease equipment and off-lease investment, are reflected in the flowing gas-well gas production costs, which are based on the cost composite for 81 Appendix B and C respondents covering their production operations in Southern Louisiana. In addition an allowance of 0.18 cents per Mcf is provided to cover separate non-plant gathering not included in production costs and 0.33 cents for plant gathering to process sub-quality gas.

We conclude that both the new gas-well gas cost and the flowing gas-well gas cost, as determined in this Opinion, include all producer incurred gathering costs. Therefore the ceiling prices herein determined are applicable to gas delivered at or beyond a central point in the field[54] under future contracts.

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[54] (1) an offshore platform to the buyer's line, (2) a central point in the field, (3) the tailgate of a natural gas processing plant, and (4) a point on the buyer's line.

Wellhead deliveries made under future contracts thus will not be entitled to the otherwise applicable ceiling price. However, rather than prescribe a specific reduction from the ceiling price for such sales at this time, we will leave the matter for determination by the Commission as

filings are made in connection with such sales.[55] We do not think it necessary to require price reductions in those few instances where gas already is being delivered at the wellhead or lease separator. Our determination on this matter is in accord with established practice in the Southern Louisiana area, where the overwhelming proportion of deliveries are made at or beyond a central point in the field. (Exhibit 28-B, Sch. 2.)

Btu Content

The Presiding Examiner summarized the facts as disclosed by the record with respect to Btu content in the Southern Louisiana area at page 181 of the initial decision:

"(1) Little or no gas contains less than 1,000 Btu's.

(2) Although Southern Louisiana contracts generally required that gas sold thereunder must meet certain stated minimum heat content levels (generally fixed at 1,000 Btu's per cubic foot), with provisions for price reductions where the Btu's fell below that standard, no Southern Louisiana rate schedules analyzed in the instant proceeding contain an upward Btu price adjustment clause.

[55] While the amount of the differential will be left to negotiation by the parties in the first instance, we will require substantial justification where the proposed reduction is less than one-half cent per Mcf. Furthermore, the burden will be on the producer to justify the actual reduction.

(3) The weighted average Btu content of the gas sold in 1960 and 1961 for which actual Btu figures were reported was 1,053 and 1,056 respectively. However, the heat content of almost three quarters of this gas fell in the narrow range of 1,026 to 1,075 Btu per cubic foot. (Staff initial brief, p. 255.) It also appears that no gas was sold with less than 1,000 Btu content, that approximately 7 percent was sold with less than 1,025 Btu's and approximately 18 percent was above the 1,075 Btu content level."

Under these circumstances the Examiner agreed with the Staff that for purposes of determining adjustments to the base area rates, an average zone of Btu values should be established around the weighted average level of 1,050 Btu's and that, since the bulk of the gas had a Btu content in a relatively narrow range of 1,026 to 1,075 Btu's, it would be reasonable to establish a zone with an approximately 25 Btu spread on either side of the average Btu level of slightly above 1,050. Under these circumstances the bulk of the gas would require no adjustments and the approximately 18 percent requiring an upward adjustment would be partially balanced by the approximately 7 percent requiring a downward adjustment. These adjustments would be applicable to gas sold under contracts dated prior to as well as after the Commission's order in this proceeding.

It has been customary in this area as well as in most of the nation to provide for downward adjustment of price only where the Btu content of the gas falls below 1,000 Btu's. It is our desire to avoid as far as possible disturbing established practices in the industry, and to preserve quality standards already accepted. Accordingly, we will provide that no downward adjustment of the base area rates shall

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be made by reason of Btu content unless that content falls below 1,000 Btu's. Where this occurs the downward adjustment shall be made on a proportional basis from a base of 1,000 Btu.

No Btu standard as a base for upward adjustment of prices has been established in Southern Louisiana, by custom or otherwise. It has not been the usual practice in the area to provide for any upward adjustment in price by reason of high Btu content. The 1,000 Btu content commonly required by contracts in the area is a minimum standard only. It is not an indication of average quality — in fact, the average Btu content in the area was close to 1,050 on the basis of 1960 and 1961 statistics. On the basis of statistics from the pipelines' 1966 Form 2 reports, the average Btu content measured at the point of purchases has decreased somewhat and is now approximately 1,037 Btu per cubic foot.[56] These

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statistics indicate a downward trend. An area rate bonus for gas of superior quality should be allowed only for gas which is above the average in Btu content. Accordingly, we believe an upward adjustment of the base area rate should be made only where the Btu content of the gas exceeds 1,050. The increase in the applicable area rate should be proportionate to the amount by which the Btu content exceeds 1,050.

These adjustments of the area rates will be applicable to all gas produced in Southern Louisiana and are to be

[56] The calculation is based on the reported Btu content of jurisdictional gas purchases by intestate pipeline companies from independent producers with sales of over 10

used irrespective of whether the underlying content contains a Btu adjustment clause. A producer will, of course, be limited to his contract price if it is below the applicable area rate as adjusted. It should also be clear that we are *not* restricting liquid extraction or other operating practices of the industry; our quality adjustment for Btu content is solely to determine the applicable area rate for a given quality of natural gas.

A downward adjustment in the base rate for gas having a Btu content less than 1,000 Btu per cubic foot, and an upward adjustment for gas with a Btu content over 1,050 Btu per cubic foot results in a gap of 50 Btu for which no adjustment is allowed. These adjustment ranges are the same as in the *Permian* decision. We believe that a gap of this dimension is warranted for a number of reasons. First, a continuous recording of the actual Btu content of a particular gas stream is infrequent and measurement is usually at intervals during the producing life of a well and may fluctuate within a limited range between measurements. Second, the general practice of measurement of Btu content is a sampling procedure and is somewhat burdensome except for very large sales. Third, a range within which no adjustment is occasioned has, in effect, been developed by the industry in its sales contracting practices. The absence of an upward Btu adjustment in Southern Louisiana contracts in itself results in a broad range (from 1,000 Btu to above 1,100 Btu) in which there is no adjustment. Finally, since

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[56] (Continued) million Mcf in the Southern Louisiana area during 1966. The volume with reported Btu content represents approximately 82 percent of the total jurisdictional purchases. *Sales by Producers of Natural Gas to Interstate Pipeline Companies — 1966*, Table 4.

we are limiting downward adjustments to gas with less than 1,000 Btu's, it is only equitable to limit upward adjustments to gas which is materially higher than average in Btu content.

Based on estimated 1965 jurisdictional sales in Southern Louisiana of 2,820 million Mcf, the Btu adjustment herein adopted will provide additional revenues of approximately $1.7 million, or 0.06 cents per Mcf.

Quality and Btu Adjustment Procedure

The adjustment procedure set out in the initial decision p. 186-187) is reasonable and will be adopted herein. For the purposes of this Opinion, all quality measurements and adjustments are to be made from a pressure base of 14.73 p.s.i.a. and with the gas at a temperature of 60° F. The measurement for Btu content is to be made on a wet basis. See Opinion 464, 33 FPC at p. 1236-1237.

In a number of instances throughout Southern Louisiana, producers have reserved a contractual right to process their gas supply for the extraction of liquids after delivery to the pipeline. An example of this situation is where gas is sold to a pipeline at an offshore platform, the gas is then transported onshore by the pipeline, and is then run through a producer-owned processing plant, with redelivery of the residue gas to the pipeline at the plant outlet. The processing operation reduces both the Btu content of the gas stream as redelivered to the pipeline and the gas volumes due to the quantities consumed as plant fuel and shrinkage. In these situations, where the producer avails himself of an option to process the gas, both the Btu content, for the purpose of the Btu adjustment herein

prescribed, and the sales volumes will be required to be measured at the outlet side of the processing plant.

Additionally, since it is common practice for the pipelines to transport the gas some distance from the fields prior to delivery for processing, we believe it would be appropriate for the pipelines to be compensated for the transportation of the processing fuel, shrinkage losses

and other related volumes, as well as any liquids.[57] Clearly, such transportation benefits the producers, rather than the pipelines' customers, and the customers should not underwrite a transportation service of this character. The subject of compensation for this service and the amount thereof is presently under consideration in the rulemaking proceedings in Docket No. R-338, "Pipeline Costs Allocable to the Transportation of Liquids, Liquefiable Hydrocarbons, etc., for Others." The pipeline respondents in this case, and the pipeline industry in general, are hereby placed on notice that in future rate proceedings the Commission may allocate costs to the aforedescribed transportation services being rendered the producers.

The rulemaking notice in Docket No. R-338 provides that "Proposed sales involving pipeline transportation of producer liquids and or liquefiable hydrocarbons from off-shore to on-shore will be certificated with a condition that the certificate authorization is issued subject to the ulti-

[57] *Tennessee Gas Pipeline Co.*, Opinion No. 528, ... FPC ....., issued September 26, 1967, mimeo p. 9. Although the New York Commission, in its exceptions, recommends a one-cent per Mcf reduction where a pipeline transports raw gas to a producer plant and the producer exercises a right to extract liquids, the record is devoid of any evidence from which the amount of the charge or offset could be properly calculated.

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mate disposition of this rulemaking proceeding." In order to assure equality of treatment to all producers in Southern Louisiana, the applicable area rate herein permitted for a particular sale will be subject to adjustment as a result of the future determinations made in that rulemaking proceeding. The effective date of any such adjustment, and whether refunds will be required of excessive amounts collected for periods prior thereto, will also be a matter for future Commission consideration.

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SMALL PRODUCER EXEMPTION

Under the Examiner's decision the same simplified procedures applied to individuals and companies qualifying as small producers operating in the Permian Basin would become, or would be made, applicable to small producers in the Southern Louisiana area. We agree with the Examiner on both points which he make in this section — first, that special relief is appropriate for the smaller, independent producer in the matter of certificate and rate filing and, secondly, that the many proposals for the setting of rates for the smaller producer higher than the area ceilings are clearly inappropriate as being inconsistent with the area pricing concept.

As in *Permian*, a small producer will be defined to be a natural gas company having jurisdictional sales of less than 10,000,000 Mcf annually on a nationwide basis. The combined jurisdictional sales of affiliated companies are to be considered as the sales of a single producer. Companies or individuals in Southern Louisiana qualifying as small producers will be granted small producer certificates pursuant to Section 7 of the Act authorizing all future small producer sales in the area at or below the applicable

area ceiling rate, thereby eliminating the need to obtain separate certificates for each sale.

Order No. 308, 34 FPC 1202, issued October 29, 1965, Relief From Filing Requirements Under The Natural Gas Act For Small Producer Sales, amended the Regulations Under the Natural Gas Act by adding a new section, Section 157.40, granting relief from the normal certificate and rate filing requirements to small producers operating in the Permian Basin area. We declined at that time and earlier in Opinion 468 to extend the same coverage to pricing areas outside the Permian Basin on the ground that a specific area rate was a prerequisite for the issuance of the small producer certificate. We believe that this coverage should now be extended, under the same terms, to the small producers operating in Southern Louisiana. Accordingly, we are issuing an amendment to Section 157.40 which has the effect of extending

its coverage to Southern Louisiana to provide for the issuance of small producer certificates at or below the area ceilings herein found to be just and reasonable.

In addition to laying the foundation for the simplified small producer procedure, the Commission in Opinion 468 exempted small producers from the quality deficiency adjustment and Btu adjustment requirements. This was done on the *de minimis* principle, since it was concluded that the burden and expense involved would in most cases exceed the amount of the adjustment. As described above, quality adjustments are not a significant problem in this case and have not even been prescribed for gas sold under contracts dated prior to this Opinion, except for Btu adjustments. An upward Btu adjustment has been determined appro-

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priate for gas sold above the level of 1,050 Btu per cubic foot. In this circumstance, we believe it is appropriate to allow the small producer filing under a small producer certificate to claim any upward Btu adjustment to which he may be entitled under this Opinion for certificate and rate filings covered thereunder. This action will avoid the necessity of having a small producer separately file those rate schedules which he does not wish to have included under his small producer certificate in order to secure the benefits of an upward Btu adjustment. For future contracts, any small producer claiming an upward Btu adjustment with respect to a particular sale will also be subject for that sale to the quality adjustments herein specified.

All producers in Southern Louisiana who apply and qualify as small producers will be granted special certificates which will cover not only any future small producer sales (as defined therein) made within our area ceiling prices, but also all such sales for which a separate certificate has already been issued. These certificates will be subject to the limitation of 10,000,000 Mcf of annual jurisdictional sales on a nationwide basis and to area rate limitations. Those certificate applications within the ceiling pending before the Commission by small producers in Southern Louisiana will be covered within small producer certificates and any applications for certificates above the ceiling will be granted conditionally upon acceptance of an initial base price no higher than the ceiling.

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Recipents of the small producer certificates will be required only to file annually a simple statement in which they will state the total volume of jurisdictional sales and certify that all such sales were within the applicable area

ceiling, including any Btu and quality adjustments where applicable. The producers holding such certificates will no longer be compelled to file Forms 301-A or 301-B, nor will they be required to file individual rate schedules pursuant to Section 4(e) of the Act for the small producer sales (except where they elect to file for separate sales outside the small producer certificate). However, the Commission may, in specific cases, request the small producer to supplement his verification with a detailed quality statement and description of his individual sales, but this will not be required unless called for in the individual case. Furthermore, in light of our decision to accept all rate increases up to the area rate, holders of small producer certificates will not hereafter be required, under Section 4(d) of the Act, to file changes up to the applicable area ceiling for their small producer sales as they are made. No increases above the applicable area rate will be permitted for sales subject to a small producer certificate.

Any producer operating both in the Permian Basin area and in Southern Louisiana, and who has been granted a small producer certificate under the *Permian* decision, will have his certificate extended on application to cover his Southern Louisiana sales. The annual report thereafter filed by such producers should include a certification that the rates charged comply both with Opinion 468 and this Opinion.

Any small producers who have rates in effect which are below the applicable just and reasonable rate ceilings determined in this Opinion must file for the applicable ceiling rate within a maximum of 60 days from the date of issuance of this Opinion if they wish to collect such rate as of the date hereof. Of course, such producers must have contractual authorization to make such filings. Any producer having contractual authorization who does not

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file for the applicable ceiling rate within the 60-day period will not be permitted to charge the increase retroactively.

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Should a producer cease to be a small producer by virtue of an increase of jurisdictional sales to a level in excess of 10,000,000 Mcf in a year, or should he propose to sell at prices above the area rate, or should he make sales which do not otherwise qualify as small producer sales he must abide by the present requirements, *i.e.*, his certificate will not apply to such situations.

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PETITIONS FOR SPECIAL EXEMPTIONS

In the *Permian Basin* proceeding the Commission held that "[t]hose respondents who, by reason of special circumstances, believe they are entitled to variant treatment" should be entitled to petition the Commission for special relief.[58] We believe that similar provision should be made here. The Circuit Court of Appeals for the Tenth Circuit upon review of the *Permian* opinion indicated that the special circumstances in which relief would be given by the Commission were not sufficiently spelled out. The Supreme Court, in reversing the Circuit Court and affirming the Commission, stated:

[58] 34 FPC at p. 225.

> "One additional constitutional consideration remains. The producers have urged, and certain of this Court's decisions might be understood to have suggested, that if maximum rates are jointly determined for a group or area, the members of the regulated class must, under the Constitution be proferred oppor-

tunities either to withdraw from the regulated activity or to seek special relief from the group rates.[i] We need not determine whether this is in every situation constitutionally imperative, for such arrangements have been provided by the Commission, and we cannot now hold them inadequate.

"The Commission declared that a producer should be permitted 'appropriate relief' if it establishes that its 'out-of-pocket expenses in connection with the operation of a particular well' exceed its revenue from the well under the applicable area price. 34 F.P.C., at 226. It did not indicate which operating expenses would be pertinent for these calculations.[ii] The Commission acknowledged that there might be other circumstances in which relief should be given, but declined to enumerate them. It emphasized, however,

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that a producer's inability to recover either its unsuccessful exploration costs or the full 12% return on its production investment would not, without more, warrant relief. It announced that in many situations it would authorize abandonment under § 7(b), 15 U.S.C. §717(b),[iii] rather than an exception to the area

[i] Compare *Bowles* v. *Willingham*, *supra*, at 517.

[ii] The Court of Appeals remarked that "[o]ut-of-pocket expenses are not defined and we do not know what they include." 375 F. 2d, at 30. It is certainly true that the Commission proferred no definition, but we cannot regard this as a fatal omission.

[iii] "Section 7(b), 15 U.S.C. § 717f (b), provides that '[n]o natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.'"

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maximum price. Finally, the Commission held that the burden would be upon the producer to establish the propriety of an exception, and that it therefore would not stay enforcement of the area rates pending disposition of individual petitions for special relief.

"The Court of Appeals held that these arrangements were inadequate. It found the Commission's description of its intentions vague. The court would require the Commission to provide 'guidelines which if followed by an aggrieved producer will permit it to be heard promptly and to have a stay of the general rate order until its claim for exemption is decided.' 375 F.2d, at 30. We cannot agree. It would doubtless be desirable if the Commission provided, as quickly as may be prudent, a more precise summary of its conditions for special relief, but it was not obliged to delay area regulation until such guidelines could be properly drawn. The Commission quite reasonably believed that the terms of any exceptional relief should be developed as its experience with area regulation lengthens. Moreover, area regulation of producer prices is avowedly still experimental in its terms and uncertain in its

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ultimate consequences; it is entirely possible that the Commission may later find that its area rate structure for the Permian Basin requires significant modification.[iv] We cannot now hold that, in these circumstances,

[iv] "Indeed, Commissioner Ross has already urged that the Commission modify its area proceedings so as to reflect the essentially national character of the relevant issues. *Area Rate Proceeding (Hugoton-Anadarko Area)* No. AR64-1, 30 F.P.C. 1354, 1359-1362 (dissenting opinion). Moreover, we note the 'essential amalgamation' of the Hugoton-Anadarko and Texas Gulf area proceedings before the Commission, where 'identical issues were heard on a joint record.' 1 Joint Initial Staff Brief in Area Rate Proceedings Nos. AR64-1 and AR64-2, 1. Finally, we must emphasize that we understand the present proceeding to be merely the first of many steps toward a more expeditious and effective system of regulation."

the Commission's broad guarantees of special relief were inadequate or excessively imprecise." (390 U.S. at pp. 770-772)

In view of these statements by the Court it seems desirable to clarify the position of the Commission with respect to relief to be granted on the ground of special circumstances.

A natural gas producer is not in the same position as a pipeline, an electric company or other public utility. The usual public utility dedicates a certain amount of property to the public service and is entitled to a reasonable return upon that property. It also incurs costs in rendering its service, and these costs it is entitled to receive back out of the rates charged by it, in addition to a return upon and amortization of the property dedicated to the public service. The ordinary public utility cannot cease to render service or any part of its service without approval by a regulatory body. It cannot withdraw from public service the property dedicated to that service (with minor exceptions) without the permission of a regulatory body. In the event that its rates are not fixed at a level which will recompense the ordinary utility for the service it renders it is obviously unjust to compel the utility to continue to render that service at a continuing loss. If the ordinary utility cannot earn its costs and a fair return upon its rate base, it is frequently allowed to cease to render some or all of the unprofitable services it furnishes to the public.

The producer of natural gas is in quite a different position. If an individual company cost of service computation were to be made in his case it would include the cost of whatever exploration and development activity the pro-

ducer may have engaged in looking to the discovery of future gas. This is a very large part of the cost of producing gas — in fact, in almost all cases where an individual producer has costs which substantially exceed the average, it is because of extraordinarily large exploration and development costs in proportion to the amount of gas found. Unusually high exploration or development costs may be incurred in the case of a small producer simply because he is unlucky. In the case of large producers, spending many millions of dollars to drill hundreds of wells in many different areas, the element of luck is largely reduced by the laws of probability. In the same way that a life insurance company, while unable to predict whether it will lose money or profit on the policy of a given individual, can predict safely and conservatively that it will make a profit on its overall operations as a result of the operation of the laws of probability, so with the large gas producing company. The results of its exploration and development program, if wisely conducted, will be profitable despite the expected dry holes and other hazards incident to individual wells and fields. (It is true that in a given year exploration and development costs for a particular company may be unusually high in relation to production because many of these costs are carried as expenses in the year incurred; however, other development costs may be capitalized in full despite low proven gas reserves and limited annual gas production. Therefore, expanded exploration and development programs will, at the outset, greatly inflate the company's costs per unit of gas produced in the particular year since the results are in future rather than present gas production.)

The independent gas producer may curtail or cease its exploration and development activity at any time.[59] This

[59] The ordinary public utility does not have corresponding costs which it may curtail at will.

may be done without approval or permission from any regulatory body. A producer is required to continue to furnish gas from supplies already dedicated to interstate commerce, but he is

not compelled to make further investments, to seek further supplies or to dedicate other supplies he may have to interstate commerce. A producer determines the amount it wishes to spend on exploration and development and such expenditures are not, and probably cannot be, subject to the scrutiny of a regulatory body to determine whether the investment was prudent. Under these circumstances, there is no necessity to include in the prices granted any single independent producer an amount sufficient to enable it to continue its exploration and development activities. If exploration and development activities do not yield sufficient results they may be discontinued at the producer's option. If a producer wishes to assume the business risk that these operations will be profitable at the price allowed by this Commission, this is his decision. While in the interest of the public we have fixed prices at levels which we believe will induce the necessary exploration and development activity by the industry, we have not and cannot attempt to fix prices at a level which will fully cover exploration and development costs of the highest cost producers. We have indicated that we do not think it ground for special relief — either through increased price provisions or allowing abandonment of existing production — that a producer's overall costs (including exploration and development) are higher than the price we have permitted for the producer's gas. The producer itself may without an application to us reduce its costs by abandonment of its exploration and development activities or any part thereof, if the producer deems such activity unprofitable.

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We are concerned with the relief to be accorded a producer who has existing production dedicated to interstate commerce. We have indicated that, where the producer, in the future, would have to expend more money in order to continue to deliver the gas than he would receive for such gas, relief should be afforded. Relief would take one of two forms — either permitting the producer to cease to make deliveries from unprofitable properties, or allowing a price increase to the point where the properties would no longer be unprofitable. Of course, the producer always has the option to file for abandonment and usually does in situations where a well no longer is capable of producing oil and gas in commercial quantities. We realize, however, that there may be unusual instances where it would be the public interest to allow the producer a higher price for

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his gas, *e.g.* an abandonment could in effect be more costly to the consumers particularly if the pipeline buyer had constructed gathering or lateral lines which would now become obsolete and additionally the alternative gas supply to offset this loss would more than likely be more costly. It is our position that we should strive for optimal reserve additions at minimum costs to the consumers.

We have avoided precise specification of circumstances that could justify special relief. Producers will be free to bring before this Commission all circumstances which they feel would entitle them to relief. It remains impossible to foresee and spell out each and every special circumstance on which relief might be granted.

However, certain principles have been established. Overall high cost of service of an individual producer is not a ground for relief. The fact that current revenue from a particular well is less than the costs of continuing its produc-

tion is a ground for relief.[60] The fact that a producer can obtain a higher price elsewhere is not a ground for relief.[61] Certain producers have already requested price relief, contending that unusually high pressure, great volume, concentrated delivery points, delivery of large quantities at one point, unusually high gas quality, unusually good deliverability and the availability of gas for swing purposes justify an increased price. We have determined that none of these, nor all of them together, are grounds for price relief.[62]

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SPECIAL TYPES OF PRODUCER SALES

In an earlier section we specified the delivery points at which the ceiling prices for both new and flowing gas will be applied. However there are certain types of sales in the area which require separate consideration due to the particular contractual arrangements involved.

Where a sale is made by one producer to another producer who in turn sells to a pipeline buyer, the Examiner determined that the ceiling price would be applicable to the ultimate sale to the pipeline purchaser. He recommended that any existing difference between the price received by the original producer and the price paid by the

[60] 34 FPC at p. 226.

[61] *Harry C. Boggs*, Docket No. CI67-719, Order Adopting Initial Decision of Presiding Examiner, 38 FPC ....., issued November 7, 1967 (Examiner's Decision issued September 25, 1967); See also, *J. M. Huber Corp., et al.*, 14 FPC 340, 353, *aff'd.*, 236 F.2d 550 (CA3, 1956), *cert. denied*, 352 U.S. 971 (1957); *Harper Oil Co., Op.*, Docket No. G-14456, 22 FPC 756, *aff'd.* 284 F.2d 137 (CA10, 1960).

[62] *El Paso Natural Gas Co., et al.*, Opinion No. 484, 35 FPC 40, 43-45; remanded *sub. nom. Phillips Petroleum Co. v. F.P.C.*, 377 F.2d 278 (1967); vacated and remanded *sub nom. California v. Phillips Petroleum Co., et al.*, 391 U.S. 365 (1968).

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pipeline purchaser should be permitted to stand or be redetermined at the discretion of the two producers involved, subject to Commission approval.

However, in the situation where a sale is made by a producer to an intermediate transporter, whether a pipeline or producer, for resale to a pipeline purchaser, the Examiner recommended the ceiling price be made applicable to the sale to the intermediate transporter. (Mimeo., p. 215)

We consider the Examiner's recommendations to be reasonable and proper, and adopt them for purposes of this Opinion.

In the case of offshore production, most of the gas is purchased at the platform and transported onshore through pipeline purchaser facilities extending into the offshore area. In some instances, however, offshore gas is transported through producer-owned facilities for delivery onshore. The Examiner recommended that in such cases the producer be entitled to receive the onshore price until such time as the Commission could undertake an investigation of the offshore transportation practices and problems.

The record does not assist us in resolving this issue since almost all of the transportation facilities in question

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were authorized and constructed subsequent to 1960.[63]

[63] *E.g., Gulf Oil Corp.* and *Humble Oil & Refining Co.*, 31 FPC 789 (1964); *Gulf Oil Corp.*, 30 FPC 1559 (1963); *Humble Oil & Refining Co.*, 30 FPC 1297 (1963); *Pan American Petroleum Corp.*, 34 FPC 852 (1965); *The Superior Oil Co.*, 14 FPC 1246, amended Opinion No. 437, 32 FPC 241 (1964); *Texaco Inc.*, 31 FPC 1125 (1964), amended 36 FPC 396 (1966); *California Oil Co.*, 34 FPC 1335 (1965). The situation referred to by the Examiner, as described in Staff's brief, was the Placid Line extending to Block 198 Field. By order issued July 19, 1967, this line was authorized to be sold to Michigan Wisconsin Pipe Line Company. The producers now make delivery at the offshore platforms.

Therefore the cost questionnaire does not contain data pertaining to these facilities. For this reason we are not able to determine whether, or to what extent, an increment over and above the otherwise applicable area rate is justified as payment for the transportation provided by the producers involved.

Rather than follow the Examiner's recommendation, we think it more advisable to rely on the provisions of this Opinion outlining procedures for obtaining special relief. Those producers who consider themselves entitled to special consideration as a result of transporting offshore production to onshore delivery points may file with the Commission a petition for special relief, setting forth therein such facts and circumstances as they believe warrant the special relief sought. As stated, the Commission will deal with such petitions as promptly as possible.

FLEXIBLE PRICING CLAUSES

The Examiner limited the operation of indefinite price escalation clauses in Southern Louisiana contracts executed

prior to April 2, 1962, in two ways:[64] First, price changes under the clauses would be subject to the Examiner's general moratorium on the filing of rate increases and, second, these clauses would not be permitted to authorize rate filings above the applicable area rates subsequent to the expiration of the moratorium. Upon consideration of the exceptions, enumerated below, we affirm the Examiner's overall conclusions but do not follow the precise technique ordered by the Examiner.

The Amerada group, in excepting to the decision, alleges that there is a difference in the prices in contracts signed

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in the 1956-58 period as between those that contain favored-nation clauses and those that do not. Specifically, the producers alleged that the weighted average initial price for the period was two cents less and the weighted average base price (the average price over the entire contract) over three cents less for contracts with favored-nation clauses than for those without such provision. The producers contend that they will be seriously disadvantaged if the Commission ignores these price differentials.

The producer's argument attempts to draw conclusions from the comparative level of unregulated prices specified in contracts executed between 1956 and 1958 with and without indefinite pricing provisions. We have earlier expressed our conclusion on the inadvisability, for the purposes of this

Opinion, of relying on unregulated contract prices.[65] The record shows that there is no difference today between the currently effective rates of contracts with and without such provisions.[66] Also, the record does not show that there would be any difference in realization between the two kinds of contracts at the regulated rates which will result from the present decision.

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[64] The Examiner's discussion (mimeo p. 270) relates only to favored-nation and spiral escalation clauses. Ordering Paragraph (K), however, is broader and shows that he intended his ruling to also apply to price renegotiation and redetermination provisions. The date of April 2, 1962, is significant in that by Order No. 242, 27 FPC 339, the Commission proscribed the filing of contracts executed on or after that date containing clauses of this type. By an earlier order (No. 232A, 25 FPC 609) the Commission had provided that indefinite price escalation clauses in contracts executed on or after April 3, 1961, would be inoperative and of no effect at law.

[65] *Supra*, pp. 16-19.

[66] Exhibit 119-B; Tr. Vol. 12, p. 3643.

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The producer's argument fails to take into account the fact that new contract prices from 1956 on were strongly influenced by the "out-of-line" CATCO contracts and that the initial approval of those prices was reversed by the Supreme Court.[67] If the CATCO contracts are eliminated, the 1956 contracts with favored-nation clauses have a higher, rather than lower, initial base price than contracts without such clauses. The CATCO contracts likewise account for the alleged three cents differential in average base prices. The elimination thereof more than eliminates the price differential in the 1956 contracts.[68]

The producers claim that the favored-nation provision was utilized by pipeline buyers to secure supplies of gas at lower prices than they would have otherwise had to pay, with substantial savings to consumers. They contend that it would be unfair to retroactively expropriate a significant feature of the price bargain which formed the *quid pro quo* of the seller's commitment of the gas reserves in interstate commerce at lower initial prices. This allegation was rejected by the Commission's conclusion in Order No. 242, as well as in the *Pure Oil* case [69] and in Order No. 232A,[70]

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that indefinite escalation clauses are contrary to the public interest and should be prohibited. The evidence in the record does not support the assertion that the inclusion

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[67] *Atlantic Refining Co.* v. *P.S.C.* 360 U.S. 378 (1959). See also Opinion 398, 30 FPC 283, 288-289, affirmed, *U.G.I.* v. *Callery Properties, Inc.*, 382 U.S. 223 (1965).

[68] Tr. Vol. 187, pp. 23,567-68, 23,572-73.

[69] *The Pure Oil Company*, 25 FPC 383 (1961), affirmed 299 F. 2d 370 (CA 7, 1962).

[70] 25 FPC 609 (1961).

of an indefinite escalation clause served to reduce either the initial prices or the fixed escalations otherwise agreed to in the contracts. In any event, the producers have enjoyed the benefit of the past operation of the favored-nation clauses; but it would not be in the public interest that such clauses continue to operate in the future to the extent that they continue to provide contractual support for prices in excess of the just and reasonable area rates.

Finally, the producers argue that a prohibition of post-moratorium filings above the area ceiling under a favored-nation provision works a double hardship in that, "Since contracts with favored-nation provisions have lower average prices throughout their life, it is unlikely that contractual support under periodic or fixed escalations would be found for filing above the ceiling price." The data at transcript page 187:23,556 indicates that the weighted average initial base prices provided in contracts with favored-nation clauses ranged from 17.17 cents for contracts executed in 1956 to 20.84 cents per Mcf for contracts dated in 1960, exclusive of tax reimbursement. Existing indefinite escalation clauses will be allowed to bring prices up to the applicable area rates. This is all that the circumstances require.

Accordingly, for all of the reasons above stated, indefinite price escalation clauses in contracts already accepted for filing at the time of our Order outlawing such clauses for the future, and which have not otherwise been held inoperative, will not be permitted effect to the extent of providing contractual authorization for rate increase filings beyond the applicable area rates. In view of the general price stability provision hereafter adopted, it will not be necessary to follow the Examiner's technique of a separate limitation on the operation of the indefinite escalation clauses.

APPLICATION OF ORDER

The Examiner followed the precedent in *Permian* in providing that the rates established in the present proceeding would apply as ceilings to all sales of the respondents whether they were being made at the time the proceeding was instituted or were begun subsequent thereto. The producers contend that our order cannot have applicability to sales executed after the proceeding began. This is the same legal argument made and rejected in Opinion 468, 34 FPC at p. 237, 1075. We reject it here for the same reason.

Area rate regulation is designed both to fix the future rate (and sometimes the past, locked-in rate) for existing service and to indicate the appropriate future rate for future service. Acceptance of the producers' argument would limit the scope of regulation to only a fraction of the existing service. To regulate the rest of the existing service would require an unending series of rate proceedings. Regulation of future service would always be one proceeding away and would be accomplished only retroactively. In short, producer rate regulation not only would never be forward looking, it would never even get current, since new sales will always be executed between the date of institution of a rate proceeding and the issuance of a final order. No regulatory statute can be read to require such absurd results and the Natural Gas Act in particular has never been so read with respect to the regulation of rates to be charged by natural gas pipe-line companies.

As observed by the Examiner, the Commission's order instituting the present proceeding (25 FPC at p. 944) made all non-signatory parties on whose behalf the named respondents had filed gas rate schedules for sales in Southern

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Louisiana respondents in this proceeding. That order also indicated that the Commission might act through rules of general applicability.

Since just and reasonable rates are fixed herein for all producers in the area by virtue of the rule established in this proceeding, permanent certificates for all pending applications may now be granted.

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With respect to locked-in refund obligations under Section 4(e) rate increase filings made subsequent to the institution of the present proceeding, where the dockets involving such increased rates have not been consolidated herein, we will not order refunds at this time but will instead treat these cases by separate order.

MINIMUM RATES

In Opinion 468 the Commission adopted a minimum rate for the Permian Basin area of 9 cents per Mcf for gas of standard pipeline quality, with adjustments from the minimum price to reflect any deviations from the quality standards established in that decision. In his initial decision in this proceeding the Examiner recommended a minimum price of 13.75 cents per Mcf for sales subject to the Louisiana tax and 12.25 cents for sales not subject to tax. A producer would be eligible to file for the minimum rate without purchaser approval at any time after the final decision in this case.

We believe the establishment of a minimum price is within the scope of area regulation. However, in authorizing price increases over and above contractual limitations, our judgment must be based on requirements of the public interest rather than on the individual equities of the

parties. In *F.P.C.* v. *Sierra Pacific Power Co.*, 350 U.S. 348 (1956), the Supreme Court, in spelling out the Commission's power to authorize a rate increase despite contractual limitations, said:

> "In such circumstances the sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest-as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory." (page 355).

In our judgment the minimum price should be determined so as to provide relief from prices so low as to seriously impair the ability of producers to compete for the acquisition of leases or to otherwise participate in the necessary exploration in search of new reserves due to a lack of revenue generated from current production. The minimum price should not be used simply to abrogate contracts entered into with the full knowledge of both parties which have proved to be unwise bargains.

In our opinion the minimum prices prescribed by the Examiner are higher than required by the public interest. A minimum price of 13.75 cents per Mcf for gas subject to Louisiana tax would be only slightly more than one cent below the *ceiling price*, including tax, found to be just and reasonable for flowing gas in the Permian Basin area, adjusted to the same pressure base. 34 FPC at p. 220. Moreover, as pointed out by the Pipeline group, the gas reserves dedicated under low priced contracts tend to be poorly located or otherwise economically unattractive.

A review of the rate schedules on file with the Commission indicates that, as of January 1, 1967, there are

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only four onshore contracts that provide a contract price of less than 13.75 cents and only three offshore contracts with a price of less than 12.25 cents per Mcf. We believe these rates are in excess of the highest minimum rates that could reasonably be considered for this area. The Examiner indicated that adoption of these minimum prices would provide additional revenues of approximately $500,000 annually. Our examination shows that this figure is on the high side at the present time. Further, one producer, Union Oil Company of California, would receive the major benefit from the minimum rate.[71] In our opinion, the evidence fails

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to meet the test established in the *Sierra* case for the fixing of minimum rates. No showing has been made that the public interest requires the establishment of minimum rates in this area. Accordingly, no minimum prices will be fixed for Southern Louisiana and the parties will continue to be governed in this regard by their contractual price provisions.

ECONOMETRIC STUDIES

Part of the Staff case in this proceeding consisted of econometric studies designed to assist in clarifying some of the central issues in area rate regulation. As initially introduced, the studies were patterned after similar econometric evidence by the Staff in the *Permian Basin* case. In Opinion 468 the Commission took note of the econometric evidence and observed that "The studies indicate that advanced statistical and mathematical techniques can be useful in

[71] Union Oil's rate schedule No. 103 has a January 1, 1967, offshore contract price of 11.25 cents per Mcf. Deliveries in 1965 were 33,160,428 Mcf. An increase of 12.25 cents per Mcf would have provided additional revenues of $331,604.

understanding the interaction of the price of gas at the well-head and the demand in the market place." The Commission concluded, however, that the quantitative results of the studies could not be relied upon as a basis for its decisions, because the studies assumed a one-price system and did not allow for the industry's capability in directional drilling. Following the issuance of Opinion 468, the Staff presented alternative econometric studies designed to take account of the directionality hypothesis accepted by the Commission in its *Permian* Opinion.

The Staff alleges that its econometric presentation demonstrates that "producers will not continue to explore more even if prices are rising since higher prices result in less consumption or demand, less production and less exploration." Staff also contends, based on its studies, that the rate of "exploratory drilling, whether it be for all wells or for gas wells, is much more dependent on the rate of production and consumption than on prevailing field prices. The econometric consequences of gas price increases thus are to lessen exploration and, in the long run, to lessen the reserve additions."

A substantial portion of the Examiner's decision is given to a description of the Staff's econometric evidence and the rebuttal evidence of the Amerada witness. He found that while the econometric studies might one day prove a useful tool in area ratemaking, the presentation here made could not be relied on as a basis for the Commission's conclusions in this case.

We affirm the Examiner, for the reasons stated by him, on the issue of whether reliance can be placed on the Staff's econometric models for quantitative guidelines for the deci-

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sions which we must reach in this proceeding. We are convinced that there is sufficent economic evidence in the record, apart from econometries, on which to make our necessary economic findings. At the same time, however, we do not claim that the efficiency of producer regulation cannot be improved with the aid of econometrics and other analytical tools. The Staff, despite its limited resources, has plowed new ground in this proceeding. Should the industry as well as the Staff find it possible to pursue similarly innovative analytical efforts in the years ahead, more reliable results may well be achieved and the regulatory process will be benefited.

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REFUNDS

In Opinion 468 the Commission adopted the following position with regard to refunds:

> "We shall require appropriate refunds in the case of rates which are the subject of proceedings under Section 4(e) of the Act, and have thus been collected subject to an obligation to refund amounts collected in excess of the just and reasonable rates as here determined. In each case the proper rate level for computing refunds shall be the area rate applicable to the particular category of gas involved, as adjusted by reason of any quality deviations in the particular gas." (34 FPC at 232)

In addition, the Commission held:

> "The applicable ceiling price, including any quality adjustments, is the proper price for gas sold under a particular contract. We think it is proper and equitable to require refunds of amounts collected in excess of the ceiling price for gas sold under each contract. This has been our practice in prior proceedings under the Natural Gas Act, and on this record we see no reason,

legal or equitable, to fail to return to the wholesale customers the excess sums they have paid. To the extent that any producer receives a lesser amount than our ceilings permit it is because he has agreed to prices which yield that amount or failed to file for a higher rate.

"Refunds will be required only with respect to the rates which are the subject of Section 4(e) proceedings, and only for the periods during which such rates have been collected subject to refund.

"A refund procedure must be established. We have determined that price adjustments corresponding to departures from standards shall be left to the parties for initial determination, if they are able to agree.

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The price applicable to particular gas cannot be finally determined until the parties have determined the quality of gas and the computed corresponding price adjustments. Accordingly, each producer (except small producers, who will be considered below) shall file a computation of refunds due with respect to each rate schedule within 30 days from the date of the filing of an agreement with his purchaser as to the quality of the gas sold and the cost per Mcf of processing such gas to pipeline quality standards. If no such agreement is reached the refund computation is to be filed within 30 days from the date of Commission determination of the quality adjustments.

"In the case of Section 4(e) proceedings, the refund computation shall also be made for all periods during which rates were collected subject to refund. With regard to each rate schedule, such computation shall specify the applicable rate or rates as established in accordance with the principles set forth in this opinion (including any adjustments for quality as prescribed herein), the rate or rates collected during the period

subject to refund, the period during which any rate was collected in excess of the proper applicable rate, the volume of gas for which such excess rate was collected, and the amount of refunds due. Interest on such refunds (at the prevailing rate) shall be included in the computation.

"Each producer will be directed to retain the refunds to be made by him until further order of the Commission. Such retention shall be in accordance with the option principle established by the Commission in *Humble Oil & Refining Company*, 32 FPC 49, Docket No G-9287, *et al.*, issued July 8, 1964.

"'The rates for small producer sales as defined in the rule providing for small producer certificates for such sales proposed this date are not required to reflect any quality adjustment either for past periods or for the future. Small producer refund obligations will therefore extend only to refunding amounts collected subject to refund in excess of the amounts collectible under the base ceiling rates. If a small

producer wishes to take advantage of any permitted upward adjustment for new gas-well gas of high Btu content, he will be required to indicate also any offsetting deficiencies in quality of the gas in question by filing the same statements required of large producers." (334 FPC at 223)

As noted by the Examiner, the Amerada group, as well as other producers, object to requiring refunds on a contract-by contract basis absent Commission findings that aggregate industry revenues exceed aggregate industry costs, and that the average unit revenues of the individual producer exceed average industry unit costs. This argument was one of the major bases on which the Court of Appeals relied in reversing in part our Permian decision

and on which the court was in turn reversed by the Supreme Court. The Supreme Court has now firmly held that refunds may properly be ordered in accordance with the determination of this issue made in *Permian* and adopted here (390 U.S. at pp. 813-822).

The Examiner also observed that a question was raised in the proceeding concerning refunds in Section 4(e) cases below the "last clean rate" but that "no such concrete situation had been presented in such a way as to require resolution of the problem at this time." The Amerada group, disagreeing with the Examiner's conclusion, asserted that the issue of the Commission's authority to order refunds below the last firm rate is directly presented in this proceeding.

This issue has now been decided by the Supreme Court. In *F.P.C. v. Sunray DX Oil Co., et al.*, 391 U.S. 9, 24 (1968), the Court held that an initial price which is authorized in a final, unconditioned permanent certificate is a lower limit below which a refund cannot be ordered under Section 4(e). Accordingly, in view of this decision, no producer will be required to make refunds in a Section 4(e) docket below the rate allowed in a final, unconditioned permanent certificate previously granted in such docket. In all other respects, refunds will be required as and to the extent set out in this section.

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PREPAYMENTS

As to prepayments made by pipelines to producers under contracts requiring gas to be paid for even though delivery had been deferred, the Examiner concluded that the governing rate was the rate applicable at the time of prepayment obligation rather than the rate applicable at the time the

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make-up gas is actually delivered; that producers selling gas at rates not subject to refund, under contracts containing prepayment provisions in which deliveries were deferred, have no obligation to refund the differences between the contract rates and the area rates; and that no adjustment in future deliveries of gas would be required to reflect the difference between the area rates and the contract rates on gas for which payment had been made under prepayment provisions. We assume that in referring to "contract rates," the Examiner had in mind the rate in effect and actually charged the buyer at the time the prepayments were made whether the contract rate originally applied for or some lesser filed rate, and we so interpret his references. As sure, this comports with our prior conclusion that ". . . a take-or-pay clause requires payment to be made by the purchaser on the same basis as though gas had been delivered physically at the point in time at which the obligation to pay arose under the take-or-pay clause."[32] We adopt the Examiner's disposition of this issue.

Since the date of the initial decision the Commission has issued Order No. 334, 37 FPC 110, providing a minimum 5-year make-up period in new contracts. The order provides that the rule therein prescribed would be applicable to gas contracts executed after February 1, 1967, as well as in the case of any certificates previously issued which had been conditioned to be subject to the final outcome of Docket No. R-199. Accordingly, any dockets herein involved having this condition in the initial certificate are bound by that rule and the requirements thereunder.

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[32] *Union Texas Petroleum, et al.*, Opinion No. 436, 32 FPC 254, 266 (1964).

SETTLEMENT PROPOSAL

On April 26, 1968, a settlement proposal was filed in these proceedings by Texaco Inc. on its own behalf and on behalf of a large number of independent producers who, with Texaco, are parties to the proceedings. Subsequently, on various dates during the month following the filing of the proposal, a number of other producers moved for adoption and ratification of the settlement proposal, either in whole or conditionally. During this same period responses were received from many of the pipeline companies buying gas Southern Louisiana and the distribution companies whose gas originates in Southern Louisiana and who will be affected by the final resolution of these proceedings. With a few exceptions, most of these parties recommended acceptance of the settlement offer as filed. Beginning about May 23, 1968, a number of objections to the settlement were received. The parties objecting included certain producers and distribution company interests and the New York Public Service Commission. On June 21, 1968, the producers proposing the settlement submitted a motion for leave to file a reply to the answers in opposition to the settlement proposal. The producers' reply was attached to the motion. We have accepted all filings made in this proceeding concerning the settlement proposal.

Prior to discussing the actual terms of the settlement proposal, a preliminary observation seems in order. It is obvious to us that a great deal of time and attention has been devoted by numerous, highly qualified persons to the formulation of this settlement effort and in the preparation of the responses to the proposal. This conclusion is based not only on our knowledge of the negotiations which pre-

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ceded the filing of the settlement offer, and the completeness of the proposal in its coverage of a great number of the vitally important issues involved in this proceeding, but also from the fact that it has been supported by many parties with diverse interests. Thus, many of the producers, pipeline companies and gas distribution companies who previously have taken positions varying substantially from the terms presented in the settlement proposal have signified their acceptance of the settlement and have recommended is adoption. Although we herein determine, for the reasons given, that the proposal cannot be accepted as a settlement apart from the decision

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of this case on the merits, we have considered the proposal with great care in light of the record and have given close attention to the settlement terms proposed and the arguments, pro and con, addressed to the individual provisions and the effect of the proposal as a total package. It is our conviction that the settlement effort has been highly useful to the industry and to the furtherance of just and reasonable rate regulation under the Natural Gas Act.

In view of our disposition of the settlement proposal, it is not necessary to recite its terms at length. Briefly summarized, the offer proposed a three-price system dependent on the date of first delivery under the particular contract. For those contracts with a date of first delivery before January 1, 1961, an onshore ceiling price was proposed of 18.75 cents per Mcf or the last firm rate, but not to exceed 20.25 cents. For offshore production the ceiling rate would be set at 17.75 cents or the last firm rate, but not in excess of 18.75 cents. Where the contract does not provide a price as high as 18.75 cents onshore or 17.75 cents offshore, the contract

rate would be charged, but not less than 15 cents onshore or 14 cents offshore. A full moratorium would be provided until January 1, 1973, on all rate increases and until January 1, 1978, on increases above 20.25 cents onshore and 18.75 cents offshore.

The second pricing period would cover gas sales with a date of first delivery between January 1, 1961 and December 31, 1964. For these sales the onshore ceiling would be 19.5 cents or the last firm rate, but not more than 20.5 cents. Offshore, the ceiling rates would be 18.5 cents or the last firm rate, not to exceed 19.5 cents. As in the first instance, a producer whose contract did not permit charging the ceiling rate would be limited to his applicable contract rate, with the same limitation on minimum rates. No rate increases would be permitted until January 1, 1970. Contractually authorized increases would be allowed after that date up to 20.5 cents onshore and 19.5 cents offshore, at which levels the rates would be held until January 1, 1975.

Where the date of initial delivery was on or after January 1, 1965, the settlement agreement proposed charging the contract rate, but not more than 21.0 cents onshore or

20.0 cents offshore, with the same respective minimum rates. A moratorium on all increases above 21.0 cents onshore and 20.0 cents offshore would be provided until January 1, 1974. Contractually authorized increases to these levels would be permitted in the interim.

The proposal established various periods when the producer could file contractually authorized rate increases. Future rate increase filings could also be precipitated by the Commission's decision to suspend and set for hearing

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prior rate increases previously filed under the proposal. The additional increased rate filings, however, could not be placed into effect until determined to be just and reasonable.

The settlement offer provided for refund of varying percentages of the difference paid by a buyer and the immediately effective settlement rate or the last firm rate, based on when the gas was delivered. Other provisions covered compensation for liquids transportation with respect to sales with first delivery after January 1, 1965, the filing of price increases to reflect tax increases, production from new zones or horizons (application of the settlement rates for sales commencing after January 1, 1965, to gas produced from a new producing zone or horizon on previously dedicated acreage, subject to certain conditions relating to separate reporting and apportionment of the contract rate-of-take), and the pricing of gas produced offshore but delivered onshore by the producer as onshore gas. The settlement also provided for certification of contracts pending certification but not currently undergoing court review generally at the maximum rates permissible for gas deliveries commenced in each of the respective time periods (the only exception would be for the first time period where the rates would be 20 cents onshore and 18.5 cents offshore.

While it is clear that the objections which have been filed to the settlement render the proposal ineffective as a settlement, it likewise appears that we are obligated to consider the filing on its merits as a recommended disposition of these proceedings. *Michigan Consolidated Gas Co., et al.* v. *F.P.C., et al.*, 283 F.2d 204, 224, rehearing denied 283 F. 2d 225 (CADC, 1960), cert denied *sub nom.. Panhandle Eastern Pipe Line Co.* v. *Michigan Consolidated Gas Co.*, 364 U.S. 913 (1960).

as noted above, the proposal is opposed in part by some producers and is opposed in its entirety by some consumer interests. We agree with the arguments made by these parties opposed to the settlement proposal that the public interest would not be served by authorization of the settlement rates. In this decision we determine those rates which, in our opinion, can be considered just and reasonable under the Act. Neither the rates nor the rate structure proposed in the instant filing is consistent with those determinations. The rates contained in the proposal, which are higher than those we found to be just and reasonable, are sought to be justified on the ground that the pipeline buyers and consumers will be spared the possibility of substantial rate increase filings at the expiration of the moratorium period anticipated in this proceeding. While it is true that the proposal would modify the operation of contractual escalation provisions as they now exist, and would limit, to a substantial degree the escalations permissible under the contracts, the value of this advantage is negated by the fact that the proposal does not limit the initial or subsequent rate levels specified in contracts for new gas or new acreage.

In addition to our fundamental objections, we believe that certain detailed provisions of the proposal would not be in the public interest. For example, we agree with the protestors that neither the use of the date of first delivery rather than the contract date for pricing purposes, nor the lengthening of the time period prices provided to all types of gas, nor the differential of only one cent between onshore and offshore production in most instances is supported in the Permian precedent or the record in this case. We also find no support for the limitations proposed on the pro-

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ducer's refund liability for excess collections made prior to 1963. The provision dealing with compensation to the pipelines for offshore liquid production transported ashore by them and recovered by producers at onshore plants is limited to production in the third pricing category. No explanation is provided, and none is apparent, why all such liquids transportation should not be recompensed the pipelines, irrespective of the date of contracting or first delivery

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of the gas supply. Moreover, the "adequate compensation" which would be provided even in the limited instance covered by the proposal is not defined.

The decision dealing with the proper price for new production on committed acreage has been deferred, as previously discussed, for resolution in the Docket No. AR64-1 proceeding where a record on this subject has been compiled. A decision here could operate to prejudge our consideration of that record on such issue. Finally, as noted by various parties, the proposal in its existing terms could be construed as according preferential rate treatment to the pending Rayne Filed and Bastian Bay transactions, Docket Nos. G-12446, *et al.* and CP66-269, *et al.*

In the circumstances here, no issues can be severed from these proceedings as truly "settled". In this situation the proposal serves at most as an additional pleading, albeit one to which many of the conflicting interests would subscribe as a package, but which binds no party to its constituent parts. Moreover, in view of the virtual certainty of further administrative and judicial litigation by the nonconsenters, it seems doubtful that any benefit in the way of the elimination of further litigation would be achieved

by adoption of all or any part of the proposal. Accordingly, the petition for an order promulgating the settlement proposal filed April 26, 1968, will be denied on the ground that an order of such character would not be consistent with the public interest, and that the rates and other terms as proposed are not consistent with the standards of Sections 4 and 5 of the Natural Gas Act.

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PRICES AND GAS SUPPLY

In establishing the ceiling prices in the Southern Louisiana area we believe that other factors as well as the unit cost of gas must be considered. The need for obtaining additional supplies of gas in the light of probable future demands, the extent to which other forms of energy may be substituted economically in serving consumers, whether exploration and development activities should be fostered at this time or at a later date, the extent to which price incentive may be useful as a tool in stimulating exploration and development that might bear upon the prices to be established here — all should be considered before final determination is made with respect to the maximum prices to be allowed producers.

So far as can be determined from the evidence available in this proceeding, the trend of unit cost of gas-well gas is slightly downward after 1960. Producer interests contend that many expenses have increased since 1960, including cost per foot of wells drilled, cost of pipe and general labor cost. The producers have also pointed out that there are fewer wells being drilled and total drilling footage is less than a few years ago. There is every indication, however, that where costs have increased they are offset by the larger amounts of gas found per well drilled and per

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foot drilled. Total gas found, total gas produced and total proven reserves were greater in 1967 than in 1960. An examination of the amounts realized from gas liquids indicates that liquid credit is increasing yearly. This is due in large part to the practice of extracting liquids from high liquid content production from offshore Southern Louisiana, where gas and entrained liquids are transported ashore by the pipelines but producers more and more are extracting the liquids for their own benefit at onshore processing plants. Despite the greater cost of offshore drilling facilities it has not been demonstrated that the unit cost of gas is greater offshore than onshore. The unit cost of finding and producing gas-well gas appears to be declining slightly, so far as available statistics indicate.

In addition to natural-gas reserves within the boundaries of the United States and the adjacent underwater continental shelf, there are extensive gas reserves in Canada and to a lesser extent in Mexico which might be, and to an extent are being purchased to supply some of the needs of the American consumer. In most sections of the United States these supplies would be more costly than gas produced in this country. A large number of pipelines would have to be built if importation of this foreign gas were to be greatly increased or if it were to be made available to large sections of the country now served

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by domestic gas. Since the price allowed foreign producers is not under the control of this Commission, and since the governments of Canada and Mexico are naturally more interested in obtaining the best possible prices for their exports than in assuring low price to the American consumer, it is to be expected that it will be more difficult to

resist upward pressure on prices for foreign gas, than for domestic gas. For all these reasons it is our judgment that gas produced in Canada and Mexico, while valuable as an addition to domestic sources, should not be looked to or depended upon for a major supply of gas to American consumers now or for the foreseeable future.

The looming importance of liquified natural gas should not be overlooked. Already shipment of such gas from Alaska to Japan has been authorized. Before many years have passed liquified natural gas from Alaska and Venezuela may be shipped to coastal cities and sold at prices not out-of-line with natural gas delivered there by pipelines. Again, this should be regarded as a valued increment rather than a major source of gas supply. Areas where water transportation cannot be used for the shipment of liquified gas will propably not use it in substantial quantity for the foreseeable future.

An increasing number of sources of energy are being found. Nuclear power, which has grown much faster than almost anyone predicted, will furnish greatly increased amounts of energy in the years to come. Science is expected to unlock other sources of power. Solar energy, geo-thermal energy, the harnessing of tides and ocean currents are among the prospects for new power. New means are being found and will be found to utilize the energy of our vast coal resources. Mine-mouth electric generating plants will become more common with the continued development of extra high voltage long distance transmission lines. Coal slurry, more economical mining techniques, and the development of more means of manufacturing gas from coal will all promote increased use of this great natural resource. While hydroelectric facilities cannot be expected to produce a large percentage of the increased amounts of energy which will be required by consumers in the years to come,

new projects and improvements to existing projects will substantially increase the amount of energy available from such facilities. Yet, with all this, there seems no doubt that natural gas will be a major and vital source of energy for many years to come and nothing should be done at this time which would prevent the exploration and development necessary to make available this clean, convenient, economical and increasingly popular energy source. It should not be overlooked that electricity, often considered a rival to gas, is itself generated by gas in many sections of the country. With the increasing concern in this

country for elimination of sources of air pollution, the use of gas in place of other fuels in electric generating plants and in other industries is one of the recommended means of reducing air pollution. The very fact there are limitations on such use of gas, imposed by supply considerations and the restricted capacity of pipelines to transport it in sufficient quantities, is one indication that exploration for and development of this vital resource should be fostered rather than inhibited.

It is true, of course, that there is only so much natural gas to be discovered. No amount of incentive can cause the discovery of gas which does not exist. It is also true that the cost of gas is greatly increased if the expense of discovery and development is incurred and the gas is then held in the ground for many years before being produced. It would not be advantageous to the consumer or the economy to have the producing industry embark upon a wholesale exploration program which would discover virtually every recoverable source of gas merely to have that gas held for use at some long distant future date. Whether discovered

or undiscovered, the gas will still be there. Its discovery and development, ideally, should take place as close as possible to the time of its use. On the other hand, exploration and development cannot be turned on and off like water from a faucet, as the producers have rightly said. If gas exploration and development were cut back today, geologists and engineers would find other work and the colleges and universities would cease to train men for a field in which they could find no employment. Years hence, when exploration and development again become important, there would be too few skilled men available to do the job. In determining prices, then, care must be taken that exploration and development will be sustained at an adequate level over the long run and that available supplies are not allowed to dwindle to a dangerous level.

In reaching our determinations as to prices we are moved to caution by the fact that there is relatively little experience with the effects of substantial price reductions in this field. The argument has been made that higher prices for gas would not increase exploration and development but rather would curtail it. This argument is based on the contention that within a realistic price range, exploration, development and production respond more to demand than to price. Its advocates contend that the prices received by producers over the years have been sufficient to cause them to find, produce and market all needed supplies of gas and that they will continue to do so to the

extent there is an available market. Since that market will increase more rapidly with lower prices than higher prices, it is argued that a reduction in prices, by stimulating demand, will also stimulate exploration, development and pro-

duction, whereas a higher price, by curtailing demand, will result in lesser exploration, development and production. This contention was not accepted by us in the *Permian* decision for the reason that the evidence supporting it had been compiled on the assumption of a one price system and it was not shown that a two price system, with its lesser average cost to the consumer in proportion to the higher incentive contained in the higher price for new gas, would have the same effect. We find nothing in the present record which would persuade us to depart from our previous determination.

At the present time we are in the midst of a period of inflation. While it is to be hoped that the recently enacted Federal tax increase and the accompanying economy measures will dampen inflationary forces, should we experience further inflation it would tend to offset the cost savings accomplished by technological improvements in searching for, drilling for, and producing gas. There is no question but that technological advances have operated to reduce costs which would otherwise have been incurred. The producers drill today economically to depths that would have been impossible a scant few years ago. Gas producers capture increasing amounts of liquids. We fully expect that technological improvement will continue especially in the relatively new offshore area with which we deal in this proceeding.

PRICE STRUCTURE AND PRICE STABILITY

In exercising our statutory responsibilities under the Natural Gas Act, we shall establish just and reasonable ceiling prices for the Southern Louisiana area and shall establish limited price changing mechanisms to foster sub-

stantial price stability. We recognize the interrelationship of price level and duration as a matter of legitimate business concern to all segments of the gas industry and to the gas consuming public. Accordingly, we deal with both facets of the equation here.

As previously stated, we will set ceiling prices for gas subject to the Louisiana severance tax of 18.5¢ per Mcf for pre-1961 gas-well gas and all oil-well gas; 19.5¢ per Mcf for gas-well gas sold under contracts dated January 1, 1961 through September 30, 1968; and 20¢ for gas-well gas sold under contracts dated October 1, 1968 and thereafter. For gas not subject to the Louisiana tax the relevant maximum base rates are set at 1.5¢ per Mcf below those prescribed for taxed sales.

Our determinations rest on a number of factors:

(a) The determined costs of gas-well gas as heretofore found are major benchmarks. The historical average cost of Southern Louisiana gas-well gas subject to the Louisiana severance tax has been found to be 18.36 cents per Mcf, based principally on 1960 data. We have found the unit cost of more recently developed gas-well gas to be 18.8 cents per Mcf at 15.025 psia on a nationally oriented cost basis. These figures include a cost allowance of 2.3 cents per Mcf for the Louisiana severance tax, which does not apply in the Federal domain of the outer continental shelf. During 1960, according to AGD, the weighted average severance tax paid amounted to 1.83 cents per Mcf, considering both taxed and untaxed production.

(b) As the foregoing tax data indicate, there was relatively little production in the Federal domain in 1960. According to the Louisiana Department of Con-

servation, the proportions of total offshore production and Federal domain

production have since risen dramatically.[73] Thus the cost

	1960	1966
Total natural gas (gas-well gas) production, So. La.	2,026 Million Mcf	3,830 Million Mcf
Total offshore gas production	320 Million Mcf	1,042 Million Mcf
Total Zones 2, 3 and 4 production (Federal domain)	245 Million Mcf	791 Million Mcf
Offshore as a percent of total So. La.	16 Percent	27 Percent
Zones 2, 3 and 4 as a percent of total So. La.	12 Percent	21 Percent

Offshore Zones, 2, 3 and 4 are deemed to constitute the Federal domain for purposes of illustration. The exact boundary line remains in dispute.

data of record, particularly the historical cost data, are less representative of the far offshore production than they are of State-domain production.

Respondents contend but have not proven here that unit costs are higher for the far offshore reserves. The record indicates, however, as the Examiner found, the unit costs of finding and producing the new gas reserves developed throughout Southern Louisiana, at least through the early 1960's, do not exceed estimated unit costs of new gas reserves developed nationally. In recent years, Southern Louisiana has accounted for much of the Nation's new gas reserves.[74] The implication follows that if far offshore

[73] The relevant data for 1960 and 1966 are:

[74] According to American Gas Association estimates, 29.4 percent of total reserve additions were made in Southern Louisiana over the period from 1956-1966: 72,968 million Mcf out of a total of 214,743 million Mcf of gross reserve additions.

unit costs exceed the national average, as alleged, then new gas unit costs for reserves elsewhere in Southern Louisiana fall below the national average.

We recognize that certain input costs are higher in deep offshore waters than elsewhere, including the total tangible and intangible investment costs per platform and per well, and that other input costs, including time lag, may be higher. Gas reserves data have not been satisfactorily correlated, however, with such costs. In the circumstances, we believe that the question of offshore Louisiana costs should be again considered when further evidence is available with respect to sales in the far offshore zones, in conjunction with any later evidence with respect to national costs.

(c) We have studied the Examiner's discussion (Initial Decision, pp. 125-141; 256-57) of the contention that current costs of new non-associated gas will not increase in the foreseeable future and the exceptions to his findings. The relevant evidence explored this question in substantially greater depth than had the *Permian* record, and is ably summarized by the Initial Decision. We affirm the Examiner's conclusion "that there is no adequate basis in the instant record for assuming that unit costs in the Southern Louisiana area will rise in the foreseeable future." (p. 141)

(d) Apart from cost considerations, we shall continue to employ a functional, multi-price system to achieve maximum inducements to exploration and development of non-associated gas supplies. Strictly speaking, our order herein can serve as an inducement only with respect to future dedications of gas reserves. Nevertheless, we consider the multiple-vintage pricing adopted in *Permian* to offer, in the long run, a functional pricing technique which will best

tend to elicit supply at a minimum cost to the consuming public. In the short run, it is also compatible with the historical price and revenue considerations indicated elsewhere.

(e) As in *Permian*, all oil-well gas will be priced at the same level as old gas-well gas. AGD contends that old oil-well gas has a lower cost than old gas-well gas which should be reflected in the rates. As noted, oil-well gas constitutes about 17 per cent of the total area production. We adhere to the conclusion that oil-well gas is, in many respects, a by-product of crude oil and economically has a

lower cost than gas-well gas (34 FPC 190, 211), and we give that conclusion some weight in assessing the total impact of the rate levels we fix. We shall not, however, determine cost other than for gas-well gas. Although, as previously explained, the objections of *Permian* to allocating costs to all gas, including oil-well gas, have somewhat less force here, where the proportion of gas-well to oil-well activity is far higher than in *Permian*, the objections still apply. We believe that considerations of relative value (including the high quality of Southern Louisiana oil-well gas), the importance of a relatively uncomplicated rate structure, and the purposes and effectiveness of the multiprice system call for pricing all oil-well gas uniformly with old gas-well gas.

(f) The history of field prices has been summarized at page 16, *et seq.* In October 1960, the Commission established a guideline price, for gas subject to severance tax, of 21.5 cents per Mcf, later amended to 21.25 cents per Mcf, tax included, as the highest initial price at which certificates

In the same Policy Statement, a price ... mous tax, was established as the highest ... subject to severance tax, which the Com... allow to be filed without suspension as an ... all contracts dated prior to that time. We ... that in the remanded CATCO proceeding ... found 18.5 cents per Mcf to be the in-line ... 20.0¢ for taxed) contracts executed in ... 102, 109).

... Commission has several times found 20¢ ... the in-line price for taxed (18.5¢ per ... sales in Southern Louisiana under con... and thereafter. Application of this prece... general policies of the Commission has gen... with scattered exceptions) in the following ... post-1958 contracts:

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... cases, a permanent certificate has issued ... refund liability (but with prices prospec... to the outcome of this case) at the in-line ... and 18.5¢, (except that in numerous in... amounts have instead been approved at ... and 19.0¢ per Mcf.)

... other cases, a temporary certificate has been ... allowing collection of up to 21.25¢ per Mcf if ... 20.5¢ if untaxed. Such temporary certificates ... refund for the difference, if any, between ... collected and that permanently certificated. ... recent temporary certificates establish a ... price of 18.0¢ if taxed or 16.5¢ if untaxed.

... 401.

... *Petroleum Corp. v. F.P.C.*, 376 F. 2d ... 1967) remanding a number of these certificates.

In a number of instances, sellers have filed for and are collecting, subject to refund under Section 4(e) of the Act, rates higher than those mentioned above.

The average unit revenue for all gas sales made in the area to interstate pipeline buyers during 1960 was 20.73¢ per Mcf.[77] We note that of contracts on file as of December 31, 1964, those dated 1960 or earlier have an average January 1, 1965 effective price of 20.06¢ per Mcf, and those dated post-1960 have an average price of 19.48¢ per Mcf.[78] Distinguishing sales subject to the Louisiana tax from untaxed sales outside the domain of Louisiana,[79] we note the following average prices effective as of January 1, 1965, as weighted by the 1963 sales volumes.

Contracts Dated Prior to 1961

	Avg. Eff. Rate	Volume Million — Mcf
Louisiana domain (taxed)	20.32 ¢/Mcf	1,832
Federal domain (untaxed)	18.24 ¢/Mcf	267
Both domains	20.06 ¢/Mcf	2,099
Contracts Dated After 12/31/60		
Louisiana domain (taxed)	19.56 ¢/Mcf	203
Federal domain (untaxed)	19.23 ¢/Mcf	67
Both domains	19.48 ¢/Mcf	270
All Contracts		
Louisiana domain (taxed)	20.25 ¢/Mcf	2,035
Federal domain (untaxed)	18.44 ¢/Mcf	334
Both domains	19.99 ¢/Mcf	2,369

[77] 20.56¢ per Mcf at 14.9 psia, as shown in Exhibit No. 123, converted to 15.025 psia.

[78] Based on the 1963 volumes and the January 1, 1965 effective rates as shown in Exhibit No. 28-B. Excludes cancelled rate schedules and producer-to-producer rate schedules.

[79] For the purpose of these computations, sales from the disputed zone are assumed to be taxable.

The foregoing findings are based on the most recent data of record in this proceeding. Additional information has been provided to the Commission as a result of the settlement conferences held during the latter part of 1967 and early 1968. This information included, among other data, reports on 90% of the total 1965 Southern Louisiana jurisdictional sales volumes and the January 1, 1967 effective rates. A comparison of average effective rates similar to that given above but utilizing this material reveals the following:

Contracts Dated Prior to 1961

	Avg. Effective Rate
Louisiana domain (taxed)	20.40 ¢/Mcf
Federal domain (untaxed)	17.96 ¢/Mcf
Both domains	20.10 ¢/Mcf

Contracts Dated After 12/31/60

Louisiana domain (taxed)	20.26 ¢/Mcf
Federal domain (untaxed)	19.10 ¢/Mcf
Both domains	19.94 ¢/Mcf

All Contracts

Louisiana domain (taxed)	20.37 ¢/Mcf
Federal domain (untaxed)	18.44 ¢/Mcf
Both domains	20.06 ¢/Mcf

Were the prices of all gas in the above comparison reduced to the level of the cost findings (18.36 cents per Mcf for taxed gas and 16.06 cents for untaxed gas, pre-1961: 18.8 cents for taxed gas and 16.5 cents for untaxed gas, post-

1960), the total price reduction would amount to roughly $61 million annually in terms of total 1965 volumes.[80]

(g) We have considered but are unable, in this case, directly to employ the "location value" concept. Southern Louisiana gas, it is argued, is well located relative to the principal eastern and midwestern markets and, therefore, should be priced at somewhat of a premium relative to the average price for supplies of gas in the Southwest. Thus the argument suggests, particularly, that less pipeline transmission is needed for Southern Louisiana gas than, say, for Texas Gulf Coast gas hauled to interstate markets and that it is worthwhile for the interstate consumer, therefore, to offer somewhat of a premium to induce more exploration and development in the one area than the other. Proponents of the location value argument point to the historical fact that Southern Louisiana prices have averaged 2 to 4¢[81] per Mcf higher than those in the Southwest as a whole. We believe that such differences are properly to be considered in the ratemaking

process and have done so here; but they are to be explained by a variety of factors, rather than location value as such. (Thus the prices in the San Juan Basin has consistently fallen below those in the Permian Basin even though the former area is located closer to the West Coast markets.). We are particularly opposed to any implication that this Commission should require lower prices as the producers drill further and further offshore to compensate, in whole or in part, for the high costs of hauling gas onshore. We

[80] While these most recent data are not part of the record (which was closed in November 1965), we believe they are appropriate subjects of official notice here.

[81] Exh. 57, p. 18.

regard the far offshore areas as of vital potential for future gas supply and wish to encourage a continued active program of exploration as leases are made available for bidding by the Federal land management authorities.

(h). We turn now to consideration of prices for gas produced in the offshore area beyond the taxing jurisdiction of Louisiana. Upon a strict cost plus allowance plus return basis the price for this Federal domain gas should be 2.3 cents per Mcf (the amount of the tax) less than the price of gas in the Louisiana domain. This has not been the customary price differential. In the in-line price proceedings, *Continental Oil Co., et al.* (CATCO), Opinion No. 351, 27 FPC 96; *Placid Oil Co., et al.*, Opinion No. 398, 30 FPC 283; and *Union Texas Petroleum Corp., et al.*, Opinion No. 436, 32 FPC 254, remanded on this issue, 376 F. 2d 161 (CA10), we determined there should be a difference of 1.5 cents per Mcf in the in-line prices. Contracts between buyer and seller have usually included a provision that a portion of the tax payable for gas produced in the Louisiana domain should be paid by the buyer to the seller. This portion has varied considerably from contract to contract but usually exceeds 1.5 cents per Mcf. There was very little Federal domain gas prior to 1961. On the other hand, the Federal domain has constantly increased its production of gas and it is anticipated that for the future the Federal domain will be more prolific than the Louisiana domain and may well be the largest source of supply still to be developed in the United States and the adjacent continental shelf. We have noted some of the factors in the development of the Federal domain which may extend the time lag between investment and the commencement of production and thus tend to raise the cost of gas in that sub-area. The nationally-oriented cost computed in connection with the 1961-1968 gas contains relatively little information with respects to

costs at greater water depths. Moreover, we do not have separate cost figures for the Federal domain or for offshore

drilling in general. In the light of all these circumstances it is our judgment that a difference of 1.5 cents per Mcf should be used to establish the ceilings applicable to Federal domain gas in this proceeding.

(i) We believe that substantial price stability can and should be a principal objective of our determination in the public interest. In the *Permian* opinion we imposed a moratorium of approximately 2½ years upon future price increases. The Commission found that since 1960 the cost of gas production had been and would foreseeably remain "remarkably steady." So far as can be determined from the evidence available to the Commission, the unit cost of finding and producing gas has continued to remain "remarkably steady." So far as can be determined from the evidence available to the Commission, the unit cost of finding and producing gas has continued to remain "remarkably steady." The projection made by the Commission in the *Permian* opinion has been confirmed, we believe, by the more complete data available in the 1963 census.

The Supreme Court upheld the decision of the Commission in the *Permian Basin Area Rate Cases* and held that there is no "invincible right" to raise prices under Section 4. The Court said "Nothing in §5(a) imposes limitations of time upon the effectiveness of rate determinations issued under it; rather, the section provides that rates held to be just and reasonable are 'to be thereafter observed . . .'" The Court further stated "Nor does § 4(e) restrict the Commission's authority under § 5(a); it permits the Commission to preserve an existing situation pending considera-

tion of a proposed change in rates, and thereafter to issue an order of retroactively forbidding the change . . ." It appears, then, that just and reasonable rates, when established by the Commission, may be continued as the applicable ceiling prices for all gas produced in the area. Such rates may be made applicable not only to gas sold under contracts now before the Commission but also to any other gas sales hereafter made by any producer under any contracts whatever, including future contracts in the area.

In determining the extent to which prices here established should continue to be applicable for the future, we have considered the difference between the situation as it exists here and the situation existing with respect to the *Permian Basin* case.

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The Permian Basin was involved in the first area rate proceeding before this Commission. The legality of area rates and the legality of extending them into the future by way of a moratorium has also been upheld. Predictions that the finding, production and supply of natural gas in the Permian Basin would decline and that general economic damage would result from area rate regulation seem to have been unduly pessimistic. Gas continues to be found in substantial quantities in the Permian Basin and continues to be dedicated to interstate commerce.

There is one other important difference between *Permian* and the instant case. In the case of flowing gas in the Permian Basin there were substantial reductions in price due to the poor quality of particular gas. In Southern Louisiana this situation is not present.

On the other hand, we recognize that by imposing greater price stability requirements than in *Permian* we shall sub-

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ject producers to some extra risk of a serious cost increase coupled with regulatory lag in adjusting prices to recognize the change. The risk is by no means absolute and is not excessive in the circumstances, as explained below, but it is a factor in which we weigh in our overall rate determinations. It is least significant in the case of the older contracts where most costs were sunk long ago; it is most significant in the case of the newest long term contracts which have scarcely begun to run their course.[82] However, the producers are compensated for these greater risks by the area base rates of 19.5 cents and 20.0 cents per Mcf onshore and 18.0 cents and 18.5 cents per Mcf offshore, which are significantly above the computed cost per Mcf.

The risk is further lessened by the fact that the Commission will at all times be open to a petition to waive or lift the limitation on rate change filings in light of changed

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circumstances. Moreover, in the far offshore situation, which may give the most reason to question the accuracy of forecasts based on the present record, we expressly invite a petition to reconsider the area rates whenever sufficient evidence is presented to indicate a need for revision of the ceilings.

Generally speaking, however, we do not anticipate that changes will have to be made.

At pages 63 and 83 in this opinion are set forth two summaries which itemize the nationally-oriented cost computation applicable in the case of sales contracted from and after January 1, 1961, and the historic unit cost of gas prior to

[82] Industry contracting practices may recognize such a risk in the common provision for periodic escalation, often amounting to 1 cent per Mcf every five years during the 20-year term of the typical contract.

1961. Examination of these summaries reveals in the case of the nationally-oriented cost computation that only 2.70 cents per Mcf is attributable to production operating expense whereas 4.14 cents per Mcf is attributable to exploration and development cost and 9.37 cents is attributable to depletion, depreciation and amortization of and return on investment. There is no reason to believe that the 4.14 cents will significantly increase in future years. The 9.37 cents per Mcf attributable to depletion, depreciation and amortization of return on investment is subject to very little upward revision since the base for depletion, depreciation and amortization of return has already been established for gas in production.

So long as production taxes remain unchanged, the only item as to which a substantial cost increase appears at all likely is the production operating expense. Even an increase of more than 25 percent in the 2.70 cents per Mcf of production cost would equal only 0.7 cent per Mcf, the margin between the 18.8-cent cost finding for post-1960 gas-well gas and the 19.5-cent area base rate for second vintage gas-well gas. Regulatory expense, return on working capital and area gathering expense all together total 1.01 cents per Mcf. Except for the possibility of small increases in area gathering cost, no material increase is to be anticipated in respect to these items.

In the case of pre-1961 gas-well gas, where only 1.93 cents per Mcf is attributable to the equivalent of production operating expense, there is even less likelihood of significant cost increases.

Under these circumstances we think that the just and reasonable rates here established should be continued until such time as they may be changed by the Commission.

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This is not to say that hard and fast ceilings are to be imposed indefinitely, impervious to change despite inflation or other unforeseeable events in the future. As noted, opportunity will be provided whereby changes may be made by the Commission upon motion in this proceeding, and the rates here established will be modified if a showing is made that unit costs — reflecting amounts spent and reserves found — have increased to such an extent that an increase in area rates is required. Conversly, if upon appropriate motion it should be shown that one or more of the rates here established should be reduced or that different classifications are required for purposes of establishing new area rates, these changes also may be made. In addition, the possibility of special exemption offers relief in special circumstances to individual producers in connection with particular sales.

The provision of avenues of relief, the improbability in the foreseeable future of cost increases of such magnitude as to make necessary revision of the area prices established in this proceeding, and the experience and knowledge gained of the results following the *Permian* decision, as well as the desire for simplification of administration and elimination of the burden of numerous Section 4(d) filings, bring us to the conclusion that the prices here established should be applicable hereafter until changed by the Commission.

(j) The present proceeding was instituted as a rulemaking proceeding as well as a proceeding to adjudicate particular Section 4(e) and Section 5(e) cases.[83] This was not the case in the *Permian* decision. Our decision that the rates here established shall prevail until changed by the Commission is proper not only by virtue of the language of Section 5(a) quoted by the Supreme Court, but also by virtue of the rulemaking power of the Commission.

Under the rulemaking power this decision can and should reach not only the natural gas producers in the docketed proceedings but all those who are or may become producers in

the future in this area. In the *Permian* case prices for future gas, not yet dedicated to interstate commerce, were established at the area rate level, but as initial certificate prices only. In the interest of the certainty universally desired by the producers, the pipelines, the intervenors and by this Commission, we believe that the public interest will be better served by establishing both by rule and by virtue of the power conferred upon us under Section 5(a) fair, just and reasonable rates applicable to future gas. Such rates will be firm rates not subject to refund and the filing and collection of increases above such rates, subject to refund, will not be permitted unless and until the Commission grants permission for such increases.

Although it is a commonplace that the Commission may not bind its successors in office, the overall area rate levels here prescribed should carry a strong presumption of continuing validity for the vintages being priced. The promulgation of area rates in the form of a regulation which can be amended only after formal, public rulemaking procedures, should provide helpful assurance that our future actions, prior to any such amendments, will comport with the conclusions set forth herein.

(k) These considerations lead us to the conclusion that while the prices for the oldest vintage gas should (except for the offshore differential indicated above) be tied closely to our cost findings, there are valid reasons to fix the prices

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[83] 25 FPC 942, 26 Fed. Reg. 4296.

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at which the later vintages of gas-well gas are to be sold at somewhat higher levels. Moreover, we believe that the prices we are here fixing for application to future (third vintage) contracts should, in order to encourage continuation of necessary exploration and development activities and to recognize the greater uncertainties and possibilities of fluctuation to which sellers are exposed, be set at a slightly higher price than for the second vintage of gas-well gas. We shall, accordingly establish a third price vintage for future gas-well gas.

(l) In summary, on the basis of the considerations previously discussed, we conclude that the just and reasonable base rates to be allowed for gas subject to Louisiana severance tax is 18.5 cents per Mcf for gas-well gas sold under contracts dated prior to 1961 and for all oil-well gas; 19.5 cents per Mcf in the case of gas-well gas sold under contracts dated January 1, 1961.

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through September 30, 1968; and 20 cents in the case of gas-well gas sold under contracts dated October 1, 1968 and thereafter. For gas not subject to Louisiana taxing jurisdiction the relevant base rates shall be 1.5 cents per Mcf below those prescribed for taxed sales. Whenever contract terms permit (or the purchaser otherwise consents) the producer may file for the applicable maximum rate (the base rate as adjusted, if need be, for quality variations including Btu adjustment) and the Commission will not suspend such increased rate. However no producer may file for a rate in excess of the applicable maximum prescribed herein unless and until the Commission shall so permit by order.

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estimate the approximate overall impact of

reduction from
gas under
contracts $41.4 million
under post 1960 contracts $ 0.1 million
under subsequent contracts $ 7.5 million
Total $49.0 million

that, under the maximum rates here considering contractual limitations and Btu annual industry gas revenues in the area gas, taxed and untaxed, would million, or about 18.4 cents per Mcf (not revenues from condensates and entrained that these revenues will rise steadily both increase in the volumes delivered and of a from the older to newer vintage sources of

revenues allowed under the maxi- establish and the inducements offered adopted should foster an active ex- consistent with both the financial needs and the protection of the public interest.

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FINDINGS AND ORDER

consideration of the entire record in this proceed- public notice, public hearing with oppor- presentation of oral and documentary evidence,

of the schedules as on file on January volumes in 1965, and the assumption that oil- 17 percent of unmetered, mixed streams.

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for cross examination and for the submission of rebuttal evidence, initial decision by an examiner, exceptions thereto, and oral arguments before the Commission, *the Commission further finds:*

(1) Each of the respondents[85] listed in Parts I and II of Appendix A to this decision is, and at the time of all past sales with which we are here concerned was, a natural gas company within the meaning of the Natural Gas Act and is engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of this Commission.

(2) Past, present and proposed sales of natural gas to which the order herein applies are subject to the jurisdiction of this Commission.

(3) Rates for all sales of natural gas, subject to the jurisdiction of the Commission, by the producers in the Southern Louisiana area that are above the applicable rates prescribed herein, have not been shown to be just and reasonable or otherwise lawful under the provisions of the Natural Gas Act and should be disallowed, and refunds should be required as hereinafter provided.

(4) The just and reasonable rates for past, present and proposed sales of natural gas to which this order applies are the applicable area rates set forth in ordering paragraph (A) below.

(5) Contracts providing for rates in excess of the applicable just and reasonable rates determined herein are in that respect unjust and unreasonable.

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[85] Where the term "respondents" is used in the finding and ordering paragraphs hereinafter set forth, it is to be regarded as referring to all named respondents in the Commission orders issued in this case, and to all parties on whose behalf such named respondents have filed FPC gas rate schedules for sales of gas produced in the Southern Louisiana area.

(6) It is necessary and appropriate to carry out the provisions of the Natural Gas Act that the Commission adopt the orders and regulations prescribed herein.

(7) Except as herein granted the exceptions to the initial decision and proposed order should be denied.

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The Commission, acting pursuant to Sections 4, 5, and 16 of the Natural Gas Act (52 Stat. 822, as amended, 823, 830; 15 U.S.C. 717c, 717d, 717o) and sections 553, 556 and 557 of Title 5 of the United States Code (the Administrative Procedure Act, 60 Stat. 238, 239, 241, 242, as codified September 6, 1966 by 80 Stat. 383, 384, 386, 387) *orders*:

(A) Part 154 of the Commission's Regulations under the Natural Gas Act, Subchapter E, Chapter I, Title 18 of the Code of Federal Regulations (18 CFR 154) is amended by adding a new section 154.105 reading as follows:

Part 154 — Rate Schedules and Tariffs

* * * *

§ 154.105 Area rates — Southern Louisiana area.

(a) From and after September 25, 1968, the effective date of Opinion No. 546 in Docket No. AR61-2, *et al.*, 40 FPC ....., no rate or charge made, demanded or received under a rate schedule filed pursuant to this Part for gas produced in the Southern Louisiana area shall exceed the applicable area rate prescribed by this section except in compliance with a specific order of the Commission.

(b) Applicable area rate means the base area rate established by paragraph (c) adjusted to the extent required by paragraph (d) for the deviations, if any, from the quality standards established by that paragraph.

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(c) *The Base Area Rates.* The following base area rates are hereby established subject to any applicable adjustments for quality as provided in paragraph (d):

(1) For gas-well gas sold and to be sold pursuant to contracts dated before January 1, 1961, and any residue gas derived therefrom, and for all casing-head gas and any residue gas derived therefrom sold and to be sold:

(i) *18.5 cents per Mcf* (at 15.025 psia) for gas subject to Louisiana production tax.

(ii) *17.9 cents per Mcf* (at 15.025 psia) for gas not subject to Louisiana production tax.

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(2) For gas-well gas sold and to be sold pursuant to contracts dated on or after January 1, 1961, but prior to October 1, 1968, and any residue gas derived therefrom:

(i) *19.5 cents per Mcf* (at 15.025 psia) for gas subject to Louisiana production tax.

(ii) *18.9 cents per Mcf* (at 15.025 psia) for gas not subject to Louisiana production tax.

(3) For gas-well gas sold and to be sold pursuant to contracts dated on or after October 1, 1968, and any residue gas derived therefrom:

(i) 20.0 cents per Mcf (at 15.025 psia) for gas subject to Louisiana production tax.

(ii) 18.5 cents per Mcf (at 15.025 psia) for gas not subject to Louisiana production tax.

(4) "Gas-well gas" means gas from dry gas reservoirs and gas condensate reservoirs and gas from gas-cap wells.

(d) *Quality Standards and Adjustments to the Base Area Rates.*

(1) The standards for pipeline quality gas are set forth below. The base area rates fixed in paragraph (c) shall be adjusted for any deviations from such standards in the case of contracts dated on or after October 1, 1968. However, no such adjustments shall be required in the case of contracts dated prior to October 1, 1968, with the exception of the Btu content adjustment.

(i) *Hydrogen Sulphide* — The gas shall not contain more than one grain of hydrogen sulphide per one hundred cubic feet of gas at 60° F and 14.73 psia (10 gr. per Mcf).

(ii) *Total Sulphur* — The gas shall not contain more than 20 grains of total sulphur per one hundred cubic feet of gas at 60° F and 14.73 psia (200 gr. per Mcf).

(iii) *Water Content* — The gas shall not contain in the aggregate more than seven pounds of water, either in the form of liquid or vapor, per million cubic feet of gas at 60° F and 14.73 psia (.007 lbs. per Mcf).

(iv) *Carbon Dioxide* — The gas shall not contain more than 3 percent by volume of carbon dioxide.

(v) *Other Impurities* — Pipeline quality gas shall contain no oxygen, dirt, dust, gum or other impurity in sufficient amounts to require the buyer to incur processing costs to eliminate such impurities in order for the gas to meet either customary commercial standards or the customary requirements of any of the the interstate pipelines in the area.

(vi) *Btu Adjustment* — The maximum standard will be 1050 Btu's per cubic foot of gas, saturated with water vapor, at 60° F and 14.73 psia, and

the minimum standard will be 1000 Btu's per cubic foot of gas, saturated with water vapor, at 60° F and 14.73 psia. For gas with more than 1050 Btu's per cubic foot, upward adjustments shall be made on a proportional basis from a base of 1050 Btu's. For gas with less than

1000 Btu's per cubic foot, downward adjustments shall be made on a proportional basis from a base of 1000 Btu's.

(vii) *Delivery Pressure* — The gas shall be delivered at a pressure sufficient to enter the buyer's pipeline except that a minimum of 800 psig must be available at the point of delivery.

(viii) *Delivery Point* — The gas shall be delivered at a central point. A central point includes a central point in the field, the tailgate of a natural gas processing plant, an off-shore platform to the buyer's line, and a point on the buyer's pipeline.

(2) When a purchaser buys gas which deviates from the quality standards established in subparagraph (1) above, the base area rate fixed in paragraph (*c*) shall be adjusted for any deviations from such standards as follows:

(i) In the case of contracts dated on or after October 1, 1968, the applicable base area rate shall be adjusted downward by the net cost (actually incurred prior to ultimate consumption), of bringing the gas up to standard. If the gas is brought up to standard by the purchaser, a reasonable return upon the net investment should be included as part of the cost incurred in bringing the gas up to pipeline quality. If such processing reduces the volume of the gas, the purchaser shall pay for only the volume remaining after processing.

(ii) The applicable base area rate shall be adjusted downward or upward by the amount of any applicable Btu adjustment as set forth in paragraph (1)(vi) above.

(iii) In the case of delivery by seller of gas containing carbon dioxide in excess of the standards herein permitted, notwithstanding anything to the contrary in paragraph (2)(ii), the seller shall have the alternative of receiving payment for the total volume of gas delivered, including the carbon dioxide, provided that the Btu content of the gas is measured before removal of the carbon dioxide for the purposes of the Btu adjustments specified in this order, or receiving payment for the volumes exclusive of the carbon dioxide with the Btu content measured by the volumes of gas only.

(e) The Southern Louisiana area consists of the portion of the State of Louisiana lying south of the 31 parallel and including all areas, both State and Federal, in the Gulf of Mexico off the shore of Louisiana.

(f) Any seller seeking to charge rates in excess of the applicable area rate or requesting a change in the applicable area rates must file a petition for waiver or amendment of this section pursuant to section 1.7(b) of the Commission's Rules of Practice and Procedure (18 CFR 1.7(b)) fully justifying the relief sought in light of Opinion No. 546. Unless and until the Commission grants the petition, the seller may not file rate increases in excess of the applicable area rate herein prescribed.

(B) Section 157.40 of the Commission's Regulations under the Natural Gas Act, Subchapter E, Chapter I, Title 18 of the Code of Federal Regulations (18 CFR 157.40) is amended by adding a new paragraph (d) reading as follows:

§ 157.40 Small producer certificates of public convenience and necessity.

* * * * *

(d) *Availability to small producers operating in the Southern Louisiana area.* Small Producer Certificates are also available to Small Producers operating in the Southern Louisiana area with respect to their small producer sales in that area. Small Producer Certificates will authorize sales at prices no higher than the applicable area rates specified in § 154.105. Applications for Small Producer Certificates in the Southern Louisiana area shall contain the information required in subparagraphs (2), (3) (4) of § 157.40(b).

(C) The applicable area rate as defined in ordering paragraph (A) above, shall be effective from and after the effective date hereinafter defined and any amounts collected in excess thereof from and after such effective date shall be subject to refund plus interest at 7 percent. In addition, with respect to the rates involved in the Section 4(e) proceedings set out in Part II of Appendix A, the applicable area rate as defined in paragraph (A) above, shall be effective from the date such Section 4(e) rates were collected subject to refund and all amounts collected under those Section 4(e) rates prior to the effective date of this Opinion in excess of the applicable area rate shall be subject to refund from the date such excess was collected plus interest at the rate specified in the respective Section 4(e) proceeding, in

accordance with the provisions of ordering paragraphs (F) and (G) herein; provided, however, that with respect to such 4(a) dockets no refunds are required below the rate allowed in a final, unconditioned permanent certificate previously granted for such sale.

(D) Within 45 days from the effective date hereinafter defined each respondent shall file a supplement to each applicable rate schedule, effective as of the effective date hereinafter defined, reflecting any reductions required to bring any or all of its rates into conformity with the applicable base area rate established by ordering paragraph (A) herein.

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(E)(1) Each person having on file with this Commission a rate schedule with regard to gas produced or sold within the Southern Louisiana area, or hereafter filing such a rate schedule (including a contract or amendment adding acreage or new reserves) shall, with regard to such rate schedule or amendment, file within 90 days from the effective date hereinafter defined, or within 90 days from the date of filing of the rate schedule or amendment, whichever is later, a statement in conformity with Appendix G hereto; *provided,* however, that with regard to contracts or amendments dated prior to October 1, 1968, the information requested in Section 6 of Appendix G may be omitted. The statement filed with respect to a contract or amendment dated on or after October 1, 1968, shall set forth either that the gas accords with all pipeline quality standards established herein, or in which respects the gas deviates from the particular quality standards established herein; the agreed cost to the purchaser of processing the gas to bring it to the pipeline quality standards established herein with respect to each quality deviation; any upward

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or downward Btu adjustment; and the resulting applicable area rate for the gas. All statements herein required shall be signed by both the seller and the purchaser. If the seller and the purchaser are unable to agree upon any or all of the particulars entering into the computation of the applicable area rate, the seller shall file the statement herein required which shall indicate the absence of agreement and supply the information required to compute the applicable area rate as well as the contentions of the parties with respect to the quality and amount of the adjustment for any item in dispute. The purchaser may file a separate statement setting forth its views within the period herein provided.

(2) The statement filed hereunder which reflects full agreement between seller and purchaser shall be deemed accepted by the Commission unless the Commission, within 120 days after such filing, shall otherwise order. In the event of disagreement between the seller and purchaser or, where the Commission otherwise determines that the statement filed is inconsistent with the provisions of ordering paragraph (A) herein, the Commission will after appropriate proceedings, prescribe the applicable area rate to be applied as of the effective date hereinafter defined.

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(3) Any respondent listed in Part I or Part II to Appendix A will be exempt from filing the statement required by subparagraph (1) hereof for any sales which are "small producer sales" as defined in Section 157.40 with respect to sales in Southern Louisiana in accordance with Section 157.40(d) prescribed herein if a producer seeks to qualify thereunder. If the Commission subsequently finds that such a producer does not qualify as a

small producer such applicant shall be required to file the statement required by subparagraph (1) hereof within 90 days after any such Commission finding.

(F) *Refund Reports.* Within 120 days from the effective date hereinafter defined a refund report shall be filed with this Commission in triplicate, and one copy served on the buyer, by each respondent involved in one or more of the Section 4(e) proceedings set out in Part II of Appendix A to this decision and as to which refunds are required under the terms of this decision. Within 20 days from the filing of the refund report the buyer shall file its written concurrence or disagreement with such report. The report shall set forth the following information (if more than one rate schedule is involved the respondent shall supply the information for each schedule separately):

(i) The rate collected during the period subject to refund, and the periods during which each rate was collected.

(ii) The volume of gas sold at each such rate.

(iii) The difference between the total amount collected during the period subject to the refund and the amount that would have been collected at the applicable area rate as defined herein, subject to the proviso of ordering paragraph (C). If seller and buyer do not agree upon the items necessary to the computation of said rate, the seller shall make this computation on the basis of the information supplied by the seller in the statement required by ordering paragraph (E) subject, however, to the terms of subparagraph (2) thereof.

(iv) The interest, at rates as specified in each Section 4(e) proceeding, on the above refundable excess revenues. The interest shall be calculated to the date of the refund report.

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(G) *Treatment of Refunds.* Each respondent shall retain the amounts shown in the report required under ordering paragraph (F) subject to further order of the Commission directing the disposition of those amounts. If a respondent elects to commingle these retained refunds with its general assets and use them for its corporate purposes, it is authorized so to do after notice to the Commission; and it shall pay interest thereon at the rate of 6.5 percent per annum on all funds thus available to the date on which they are paid over to the person ultimately determined to be entitled thereto in a final order of the Commission. If a respondent elects to deposit the retained refunds in a special escrow account, the respondent shall make such deposit and shall tender for filing on or before the date of the filing of the refund report an executed Escrow Agreement, conditioned as set out below accompanied by certificate showing service of a copy thereof upon each of its jurisdictional customers. Unless notified to the contrary by the Secretary within 30 days from the date of filing thereof, the Escrow Agreement shall be deemed to be satisfactory and to have been accepted for filing. The Escrow Agreement shall be entered into between respondent and any bank or trust company used as a depositary for funds of the United States Government and the agreement shall be conditioned as follows:

(1) Respondent, the bank or trust company, and the successors and assigns of each, shall be held and formally bound unto the Federal Power Commission for the use and benefit of those entitled thereto, with respect to all amounts and the interest thereon deposited in a special escrow account, subject to such Agreement, and such bank or trust company shall be bound to pay over to such person or persons as may be identified and designated by final order of the Commission and in such manner as may be therein specified.

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(K) Twenty-five copies of any applications for rehearing or petitions for reconsideration shall be filed with the Commission in addition to the copies served on the parties to this proceeding.

(L) The Secretary shall cause prompt publication of the findings and ordering paragraphs, together with notice of the availability of this entire Opinion, to be made in the Federal Register.

By the Commission.

Gordon M. Grant,
Secretary.

(SEAL)

This opinion was adopted before
Commissioner Ross left the Commission.

APPENDIX A

PART I
(Revised 8-31-68)

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Respondents[1]

Aladdin Exploration Company, Inc.
Amerada Petroleum Corporation
American Natural Gas Production Company
American Petrofina Co.
Carter, Reese E.
Cenard Oil & Gas Co.
Chance, R. L., Sr.
Cheyenne Oil Corp. of Delaware
Christie, Mitchell & Mitchell Company

[1] All persons named herein and all parties on whose behalf such persons have filed FPC Gas Rate Schedules for sales in Southern Louisiana are respondents in this proceeding including their successors and assigns.

of Texas
Anadarko Production Co.
Apache Corp.
Arnold, Agnes Cullen, *et al.*
Arnold, Isaac
Ashland Oil and Refining Co.
Atlantic Richfield Co.
Austral Oil Co. Inc.
Barnhart, Paul F.
Bass, Perry R.
Earl G. Bateman, d b a,
Bateman Drilling Co.
Beck Oil Co.
Bel Oil Corporation
Benedum Trees Oil Co.
Benin Oil Company
Berkshire Oil Co.
Bradco Properties Inc.
The British American Oil
Producing Co.
Brown, George R.
Brown, Herman
Brunner, Arnold H., & Company
Wm. T. Burton Industries Inc.
C R A, Inc.
Cabot Corporation
The California Co., a Division
of Chevron Oil Co.
Callery, F. A., Inc.
Callery Properties Inc.
Cities Service Company
Cities Service Oil Co.
Cities Service Petroleum
Co.
Cities Service Production
Co.
Coastal States Gas
Producing Co.
Cocke, W. H.
Cockrell, E., Jr.
Cole, Howard S., Jr.
Colorado Oil & Gas Corp.
Columbian Fuel
Corporation
Conover, William V.
Consolidated Gas Supply
Corp.
Continental Oil Co.
Cordell, J. H.
Crow, David, Trustee
Crown Central Petroleum
Corp.
Cunningham, James M.
Cyprus Oil Co.
Dalton, W. F., Trustee
Del Oil & Gas Corp.
(Operator) Agent for
Joe Grady S. Armstrong,
et al.
Delta Drilling Co.

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Delta Gulf Drilling Co.
Dillon, Herbert L., Jr.
Diversa Inc.
Dixon Management Corp.
Dorn & Miller Company
Drew Petroleum Inc.
El Tres Petroleum Corp.
Roy M. Huffington, Inc.
Humble Gas Transmission
Company
Humble Oil & Refining Co.
Hunt, H. L.
Hunt, Hassie, Trust
Hunt, Lamar

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Eason Oil Co.
Falcon Seaboard Drilling Co.
Felmont Oil Corp.
Fidelity Oil & Royalty Co.
Flaitz, J. M., & Mitchell, R. B.
F. O. Corp., The
Forest Oil Corp.
Frankel, J. R.
Freedom Minerals, Inc.
Gas Gathering Corp.
General American Oil Company of Texas
General Crude Oil Co.
Geological, Geophysical Associates, Inc.
Getty Oil Co.
Gilger, C. C.
Glassell, Alfred C., Jr.
Goodrich, H. R.
Goodrich, R. H.
Grigsby, Jack W.
Gruy Management Service Co.
Gulf Interstate Oil Co.
Gulf Oil Corp.
Halbouty, Michel T.
Harbor Oil Co., Inc.
H. L. Hawkins & H. L., Jr.
Helis Petroleum Corp.
Helis, Wm. G., Estate of
Herrington, Mrs. Louise H.
Hibbert, R. E.
Hubbard, R. E., Jr.
Hudson, E. J.
Hudson Gas & Oil Corp.
Hunt, Lyda, Margaret, Trusts
Hunt, Lyda, Caroline, Trusts
Hunt, Lyda, Herbert, Trusts
Hunt, Lyda, Bunker, Trusts
Hunt, Lyda, Lamar, Trusts
Hunt Oil Co.
Hunt, W. H.
Hunt, Wm. Herbert Trust Estate
Hunt Industries
Hurley Oil & Gas Company
Hurt Oil & Gas Corp.
Jameson, F. E., *et al.*
Johnston, C. N.
Jones, Joseph M.
Kelberman, R. E.
Kerr McGee Corp.
Kilroy Properties, Inc.
King, A. P., Jr.
Lamson & Bennett, Inc.
Landa Oil Company
Langton, Claude M., Trustee
Lyons and Logan
Lyons, C. H., Jr.
Lyons, C. H., Sr.
Magna Oil Corporation
MPS Production Co. Inc.
McCain, M. F.

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J. Ray McDermott Co. Inc.
McGhee, George C.
McIntyre Oil Co.
Penton, E. Doyle, & Penton, D. N., d b a. Penton & Penton

McKnight, W. L., d/b/a LaGorce Oil Company
McLean, Harvey
Maracaibo Oil Exploration Corp.
Marathon Oil Co.
Mayfield, M. L.
Mayronne, R. W., Jr. d/b/a Riverside Oil Co.
Mecom, John W.
Mecom, John W., d/b/a Mecom Petroleum Co.
Midhurst Oil Corporation
Midwest Oil Corporation
Mississippi River Transmission Corp.
George Mitchell & Associates, Inc.
Mobil Oil Corp.
Monsanto Company
Moore, Homer T.
Mosbacher, Robert
Mound Co.
Natural Gas & Oil Corp.
Newmont Oil Co.
Nicklos Oil & Gas Co.
North Central Oil Corp.
O'Meara, M. P.
O'Meara, Robert W.
Occidental Petroleum Corp.
Ocean Drilling & Exploration Co.
Oil Participations Inc.
Owen, J. P.
Owen Production Company
Pan American Petroleum Corp.
Pareti, John D.
Peltier, Harvey
Petroleum Inc.
Petroleum Property Management, Inc.
Petroleum Offshore Leaseholds
Petroleum Leaseholds, Inc.
Phillips Petroleum Co.
Phillips, R. P.
Pioneer Oil & Gas Company
Placid Oil Co.
Pray, Max
Prentice, Robert B.
Preston Oil Company, The
Proctor, Sterrett B.
Rasberry, Elge
Ranch, Morris
Rault, Joseph M. Jr., Inc.
Rebstock & Reeves Drilling Co.
Recile, Sam J.
Rimrock Tidelands Inc.
Royalite Oil Co. Inc.
Rutherford, P. R.
Rycade Oil Corp.
Samedan Oil Corp.
San Jacinto Oil & Gas Co.
Sands, Caroline Hunt
Joseph E. Seagram & Sons, d/b/a Texas Pacific Oil Co.
Secure Trusts
Shell Oil Co.
Sinclair Oil & Gas Co.
Singer-Fleischaker Oil Co.
Skelly Oil Company
Sohio Petroleum Co.
Southdown, Inc.
Southdown Burmah Oil Co.
Southeastern Public Service Co.
Southern Natural Gas Co.

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Southwest Gas Producing Co., Inc.
Southwest Resources, Inc.
State Exploration Company
Stokes, Winston L.
Sun Oil Co.
Sunray DX Oil Company
Superior Oil Co., The
Sword Co.
Tamborello, Anthony J.
Tenneco Corporation
Tenneco Oil Company
Tennessee Gas Transmission Co.
Tennessee-Louisiana Oil Co.
Texaco Inc.
Texas Crude Oil Co.
Texas Eastern Transmission Corporation
Texas Gas Exploration Corp.
Texas Gas Producing Company
Texas Gas Transmission Co.
Texas Gulf Producing Co.
Texas Liberty Gas Corporation
Texas Liberty Oil Company
Texas National Petroleum Co.
Texas Oil and Gas Corp.
Texstar Corporation
Trahan, J. C. Drilling Contractor, Inc.
Transcontinental Gas Pipe Line Corp.
Tribune Oil Corp.
Trice Production Co.
Trunkline Gas Company
The TXL Oil Corporation
Union Oil Company of California
Union Producing Co.
Union Texas Petroleum, A Div. of Allied Chemical Corp.
United Gas Pipe Line Company
U. S. Oil of Louisiana Inc.
Vincent and Welch Inc.
W. W. F. Oil Corp.
Walker, Willard E.
Walker, W. E.
Walker, W. E. & Meeker, J. R.
Walker, W. E. & Freedom Minerals, Inc.
Webster, C. B.
Weiner, Ted
Whitehall Oil Company, Inc.
Williams Brothers Co.
Wolfe Oil and Gas Company
Wrightsman, Charles B.
Young, Marshall R.
Marshall R. Young Oil Co.
Zapata Offshore Co.

PART II

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The Section 4(e) dockets still consolidated with the AR61-2 proceeding are as follows. (The designation of the docket reflects the designation as of 8/31/68.)

Producer	Docket Nos.
Amerada Petroleum Corporation (Oper.) *et al.*	RI62-505
American Petrofina Company of Texas (Oper.) *et al.*	RI62-169
Austral Oil Company, Inc. (Oper.) *et al.*	G-13842, G-16891, G-17797, G-19641, G-19642, G-19765, G19830, RI61-179, RI62-93, RI63-138, RI63-144, RI63-146
Austral Oil Company, Inc. (Oper.) Agent for Oil Participations, Inc.	G-13177, G-16515, G-18270, G-19913, RI61-137, RI61-175, RI62-94, RI62-99, RI62-360, RI62-484, RI63-154, RI63-155, RI64-223
Benedum Trees Oil Company (Oper.) *et al.*	RI62-191
Cabot Corporation	RI62-208
Brown, George R.	RI62-145
The California Company, a Division of Chevron Oil Company	G-14313, G-16682, G-19535, G-20346
Cenard Oil & Gas Company	RI61-28
Continental Oil Company	G-16701, G-17936, RI60-165, RI60-334, RI61-470
Continental Oil Company (Operator), *et al.*	RI63-168

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Conover, William V.	RI63-68
Crescent Oil & Gas Corporation and El Tres Petroleum Corporation	G-12439
Crow, David, Trustee	G-20083
Cunningham, James M. (Oper.) *et al.*	RI60-232

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Producer	Docket Nos.
Dalton, W. F., Trustee	G-14053, G-17527, G-20441, RI60-472
Dixon Management Corporation, Agent (Oper.) *et al.*	RI61-552
F. O. Corporation, The	RI62-214
Forest Oil Corporation (Oper.) *et al.*	G-16726, G-19939, G-19940, RI61-186, RI61-187, RI62-68, RI62-69, RI63-120, RI63-136
Gas Gathering Corporation	G-20118
General American Oil Company of Texas	G-19476, G-19875, G-19924, RI61-173, RI61-321, RI62-133, RI62-234, RI62-392, RI63-127, RI63-161, RI63-162
General Crude Oil Company	G-16727
Hawkins, H. L., and Hawkins, H. L. ,Jr.	G-16314
Herrington, Louise H., Mrs.	RI62-270
Hudson Gas & Oil Corporation and Continental Oil Corporation	RI60-211
Hunt, H. L.	RI62-228
Hunt, H. L. (Oper.) *et al.*	G-13837, G-17163, G-20340, RI60-427
Hunt, H. L., *et al.*	G-20071
Hunt Industries	G-13840, G-17162, G-20445, RI60-432
Hunt, W. H.	G-19930

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Hassie Hunt Trust and The Preston Oil Company (Oper.) *et al.*	R162-227
Hurt Oil & Gas Corporation	R161-299
Jameson, F. E., *et al*	G-18672
Kerr-McGee Corporation	G-16082, G-16697, G-17155, G-17882, G-19872, G-19914, R160-452, R161-191, R161-514, R162-62, R162-378, R163-158
Langton, Claude M., Trustee	G-14054, G-17164, G-20456, R160-428

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Mayfield, M. L.	G-11615, G-16519, G-20064
McDermott, J. Ray & Company, Inc.	G-12158, R162-421
Mecom, John W.	R162-311
Midwest Oil Corporation (Operator), *et al.*	G-19912, R160-182, R161-251, R162-119, R163-116
Natural Gas and Oil Corporation	G-20239
Nicklos Oil & Gas Company, *et al.*	G-14711
Occidental Petroleum Corporation	G-12303, G-17997, R161-330
Owen, J. P. (Oper.) *et al.*, and General American Oil Company of Texas (Oper.) *et al.*	G-20555
Owen, J. P. (Oper.) *et al.*, Owen Production Company (Operator), *et al.*, and General American Oil Company of Texas (Operator), *et al.*	R161-220
Pan American Petroleum Corporation (Oper.) *et al.*	R162-359, R163-389
Penton, E. Doyle & D. N. d/b/a Penton & Penton (Oper.) *et al.*	G-17800
Petroleum, Inc. (Oper.) *et al.*	G-20276, R161-295, R162-256, R163-255

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Phillips Petroleum Company	G-11991, G-14260, G-16600, G-16712, G-16083, G-17267, G-17740, G-17920, G-20013
Phillips Petroleum Company (Operator) *et al.*	G-18414
Phillips Petroleum Company and J. C. Trahan Drilling Contractor, Inc.	G-17156
Placid Oil Company	RI62-211, RI62-257
Placid Oil Company, *et al.*	G-13180, RI62-211, RI62-257
Preston Oil Company	RI63-101
Rauch, Morris, *et al.*	G-4334
Rebstock & Reeves Drilling Company (Oper.) *et al.*	G-17738, G-19941, RI61-232, RI62-181

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Rutherford, P. R.	G-17928
Samedan Oil Corporation (Oper.) *et al.*	RI61-313
Secure Trusts	G-13839, G-17161, G-20455, RI60-429, RI62-226
Southwest Gas Producing Company, Inc.	G-18100
Sunnyland Contracting Company	G-19896
Superior Oil Company, The (A Nevada Corporation)	G-19823, G-17707, RI62-278
Superior Oil Company, The (A Nevada Corporation) (Operator), *et al.*	G-11845, G-17989, G-20577, RI63-37
Tenneco Oil Company	RI63-187
Tenneco Oil Company and Continental Oil Company	RI62-506
Tesoro Petroleum Corporation	RI62-358
Texaco Inc.	RI61-419, RI62-309

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J. C. Trahan Drilling Contractor, Inc.	R161-557, R162-103, R162-277
J. C. Trahan Drilling Contractor, Inc. (Oper.) *et al.*	R161-315, R161-550
Tribune Oil Corporation	G-6279, G-13032
Trice Production Company	G-18516
Union Oil Company of California	G-13438, G-16602, G-16021, G-19006, G-19609, R160-450, R161-80, R162-43, R163-117, R163-159, R163-160
U. S. Oil of Louisiana, Inc.	G-19874
Vincent & Welch, Inc. (Oper.) *et al.*	G-19261
Walker, Willard E.	G-18099
Webster, C. B.	G-14187
Weiner, Ted (Oper.) *et al.*	G-17993, G-19901
Wrightsman, Charles B.	R162-433

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APPENDIX A

PART III

Intervenors[2]

Alabama Public Service Commission
New Jersey Board of Public Utility Commissioners
North Carolina Utilities Commission
Pennsylvania Public Utility Commission
Public Service Commission of the State of New York
Public Service Commission of West Virginia
Public Service Commission of Wisconsin
Public Utilities Commission of the Commonwealth of Massachusetts
South Carolina Public Service Commission
The State of Wisconsin

[2] Certain of those listed, while not formally granted intervention, filed briefs or are included on the briefs filed by parties or groups participating in the proceeding.

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Algonquin Gas Transmission Company
Michigan-Wisconsin Pipe Line Company
Alabama Gas Corporation
Atlanta Gas Light Company
Baltimore Gas and Electric Company

The Berkshire Gas Company; Blackstone Valley Gas and Electric Company; Boston Gas Company; The Bridgeport Gas Company; Bristol and Warren Gas Company; Brockton Taunton Gas Company; Buzzards Bay Gas Company; Cambridge Gas Company; Central Massachusetts Gas Company; Concord Natural Gas Corporation; The Connecticut Gas Company; Fall River Gas Company; Fitchburg Gas and Electric Light Company; Gas Service, Inc.; The Greenwich Gas Company; The Hartford Electric Light Company; The Hartford Gas Company; Haverhill Gas Company; City of Holyoke, Massachusetts Gas and Electric Dept.; Lawrence Gas Company; Lowell Gas Company; Lynn Gas Company; Manchester Gas Company; Mystic Valley Gas Company; New Bedford Gas and Edison Light Company; The New Britain Gas Light Company; New Haven Gas Company; The Newport Gas Light Company; North Attleboro Gas Company; North Shore Gas Company; Northampton Gas Light Company; City of Norwich Department of Public Utilities; Norwood Gas Company; The Pequot Gas Company; Providence Gas Company; South County Gas Company; Springfield Gas Light Company; Tiverton Gas Company; Wachusett Gas Company; City of Westfield Gas and Electric Light Dept.; and Worchester Gas Light Company

The Brooklyn Union Gas Company
Central Hudson Gas and Electric Corporation
Florida Gas Transmission Company

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Consolidated Edison Company of New York, Inc.
Delmarva Power and Light Company
The East Ohio Gas Company; Hope Natural Gas Company;

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Niagara Mohawk Power Corporation
Pennsylvania Gas and Water Company
New York State Electric & Gas Corporation
Rochester Gas & Electric Corporation
Central Hudson Gas & Electric Corporation
Elizabethtown Consolidated Gas Company
New Jersey Gas Company
Equitable Gas Company
Delaware Power & Light Company
Public Service Co. of North Carolina
Washington Gas Light Company
Philadelphia Gas Works, Division of The United Gas Improvement Company

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APPENDIX B
THE DCF-PROJECT APPROACH
APPLICATION OF METHOD

The producers advocate project costing in preference to the more traditional accounting methods we use in determining the cost of new gas-well gas. The Examiner, however, agreed with both the distributor groups and the staff in finding that the project method should not be utilized in this proceeding, despite the Commission's interest in the further development of this type of cost analysis. (34 FPC 41, 42, 251, 252, 271-273) The Examiner's reasons for rejecting the project method relate both to the concepts involved in project accounting and to the adequacy of this record to provide certain essential information concerning, *inter alia*, the timing of expenditures, the timing of revenue receipts, and the proper rate of return. We agree with the Examiner that the record does not permit use of the

project method as a primary costing method for the purpose of establishing just and reasonable rates in Southern Louisiana. However, numerous producing companies use the project method, along with other economic studies such as time of payout, primarily as a means of evaluating alterntaive investment opportunities. The essential concepts of project accounting are utilized by various federal agencies. Indeed this Commission uses a similar method in connection with federal hydroelectric projects. (Opinion No. 482, 34 FPC 1462.)

Stated in its simplest terms, the DCF Project method seeks to relate the funds expended during the course of an undertaking to the revenues generated by the project through consideration of the time value of money. A project costing recognizes the timing of expenditures necessary to discover and produce a given body of gas reserves and the timing of the revenue derived from the production and sale of those reserves. This procedure implicitly recognizes the time displacement between expenditure and recoupment, and provides compensation for the postponed recovery of funds devoted to the project. The project method does not distinguish between investment outlays which are ordinarily expensed (such as dry holes) and those which are capitalized (successful well costs). All investment outlays are capitalized regardless of whether or not they are successful. Current costs, comprised of operating expenses, royalty, and production taxes, are not investments. Therefore these items are charged against contemporaneous receipts, and do not earn a return.

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When cast in a discounted cash flow (DCF) format, the project portrays year by year the dollar outflow of ex-

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penditures and the dollar inflow of revenues. Within each year expenditures and revenues are offset against each other, and a net cash flow (plus or minus) is derived for that year. The net cash flow dollars for each year are then "discounted" by the application of a rate of return so calculated that at the end of production (depletion of the reserves being costed) the project will have generated sufficient revenue to cover its investment, pay all current expenses, and provide a profit at the allowed rate on the unrecouped investment outstanding each year. Since the DCF-Project method considers the time value of money relating to the outlay of expenditures and their recoupment, the annual discount rate which balances the cash outflow and inflow over the life of the project is termed the "true-yield" rate of return. This means a return which is allowed on the "true" investment, as distinguished from booked investment. In the instant project model (Appendix C) we have used 1960 as a base year, since it provides a convenient point of reference between the investment phase and the production phase of the project: investment necessary for initial production is complete, but production has not yet begun. This means that the outstanding investment, represented in the project by the net cash flow, is compounded retrospectively and discounted prospectively from 1960. The net cash flow for 1960 is neither compounded nor discounted. The result of this computation is termed the discounted worth (or present value) of the net cash flow expressed in dollars (plus for net receipts; minus for net outlays). At the end of production, the algebraic sum of all the years' discounted worth should be approximately zero.

There are two alternative ways of comparing the DCF-Project method to the previously determined new gas-well gas cost. One method would involve making an independent

determination of the proper "true-yield" rate of return, using that rate of return in the project to compute the gas revenues and therefor the approximate cost of new gas-well gas, and comparing that cost with the cost determined under the rate base approach. This calculation is illustrated

by Exhibit 42 of witness Spain. The other method is to compute project revenues on the basis of the new gas-well gas cost, and observe the result in terms of rate of return. This method was used by witness Fraser in Exhibit 252. We think it most appropriate to follow the latter approach. As proposed in these proceedings, project accounting could be considered as allowing a return on all net outlays, as contrasted with successful investment, or investment directly related to producing wells. Moreover, when used in the DCF format, the "true-yield" return is compounded. These factors make the results of project accounting particularly dependent on the return level, and particularly sensitive to changes in the return level and timing. In view of this, and in consideration of the present record as it relates to "true-yield" return, we are in a better position to evaluate whether a given "true-yield" rate of return is within a reasonable range than to attempt to determine independently what the rate of return should be.

As advocated in these proceedings, the DCF-Project method, employing a "true-yield" rate of return, adopts the timing of finding costs from successful projects and uses that timing pattern to date all the costs from successful and unsuccessful projects. There are no data in the record indicating the timing of expenditures on leases which prove to be unproductive. More importantly, we are not convinced that these expenditures on unproductive leases

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are entitled to a return, even though the method we are here including as a comparison treats these expenditures as investment outlays and thus entitled to a return.

As we undersand, however, the industry does not use the DCF-Project method in the way it has been presented here. Rather, individual producers use the method either to evaluate whether anticipated revenues from a given project will be enough so that after discount they equal or exceed expected outlays or to asisst in determining which of two or more comparative projects can be expected to generate the higher return rate and should be pursued. The discount rate is set high enough to cover the risk of failure on unsuccessful projects. But the cost component inputs of our project already allow for recovery of unsuccessful projects: part of the dry hole cost component,

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the lease acquisition cost component, etc. Putting unsuccessful projects into the return base seems doubtful. This difference from industry practice leads to a lower discount rate than would be employed by the producers in their own project analyses.

The mechanical application of our project accounting analysis is set forth in appendix C hereto. The project is set up in a cash flow format patterned after those used by witnesses J. R. Fraser in Exhibit 252 and H. L. Spain in Exhibit 42 (Revised). When project revenues are computed at the new gas-well gas wellhead cost of 18.29 cents per Mcf,[1] and 3.30 cents per Mcf plus royalty and State taxes for liquids (adjusted to 15.025 psi), a true-yield rate of return is generated: An explanation of the DCF-Project computations and an analysis of the resulting rate of return are developed in the following paragraphs.

It is essential as a preliminary matter to distinguish between the determination of unit costs, such as successful wells, lease acquisitions, etc., and the format into which these unit cost components are placed in order to derive the overall cost per Mcf including return. In utilizing either the rate base type of calculation or the DCF Project type, it is first necessary to determine unit costs for the various individual cost items.

We have used the unit costs previously determined herein, such as 2.88 cents per Mcf for successful drilling, etc. Our project is designed to cost 1,000,000 Mcf of gas well gas reserves which are produced beginning in 1961. Therefore, in order to determine the total cost inputs, it is only necessary to multiply the applicable per Mcf costs (at 15,025 psi) by one million. As an example, Dry Hole expenses has been determined to be 1.42 cents per Mcf at 14.65 psi. At 15,025 psi this becomes 1.4563 cents per Mcf. Therefore the total dry hole cost for purposes of the project would be $14,563.

In any DCF-Project analysis of the costs of exploring for and producing natural gas, two matters are of critical importance. They are (1) the timing pattern for investment

outlays, and (2) the timing of revenue receipts. We believe the best evidence in the record concerning the timing of investments is Exhibit 248 of witness Donald W. Auten. This exhibit is a compilation of the responses to a questionnaire developed and circulated during the course of this proceeding by respondent Gulf Oil Corp. The one-page questionnaire called for information concerning the timing of

[1] New gas-well gas cost at 15,025 psi exclusive of the 0.51 cents per Mcf off-lease cost for area gathering.

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investment outlays incurred in finding and developing non-associated gas fields from which deliveries of gas were first made during the year 1950.[2] Of the approximately 500 producers who were contacted, thirty companies actually submitted completed questionnaires. Reporting, obviously, was on a purely voluntary basis. Six responding companies were excluded by Mr. Anter for various reasons set forth in his related testimony (257 30556). The remaining 24 companies accounted for approximately 10 percent of the total U.S. gas production for 1962. The exhibit reflects data for 85 of their gas fields.

Both staff and the distributors, particularly AGD, have strenuously pressed objections to Exhibit 248 on the grounds that the sample is too small, and is biased due to self selection. They also allege possible discrepancies in reporting due to varying interpretations of the applicable instruction. The Examiner refused to exclude Exhibit 248 from the record, and we found no reason to disturb his ruling when the matter was before us on an interlocutory appeal by AGD, although our decision was based on procedural grounds rather than on the merits, (34 FPC 870). We recognize these data are not free of infirmities. The sample is small and represents only a fraction of gas leases. The survey was undertaken on a voluntary basis, which unavoidably leads to speculation as to whether unfavorable reports were withheld by potential respondents to the survey. We would also point out that in our opinion it was not appropriate to exclude cycling leases from the survey. Furthermore, the respondent data concern only projects with a full scale of exploratory activity; other projects such as offset leases, which would have shorter lag, were not called for in respondent's survey.

[2] In our model we have assumed 1961 to be the year of first production since this is consistent with the underlying unit costs. This does not affect the use of Exhibit 248 for timing purposes.

Nevertheless, the study provides the best picture of investment timing in the record. In fact, Exhibit 248 is the only empirical data in this record addressed to the matter.

We should repeat here that we are using Exhibit 248 only to establish the necessary timing pattern of investments, not the amount of investment.

The second essential consideration is the timing of revenue receipts. This in turn depends on the pattern of gas and liquids production. It is necessary, therefore, to establish a representative pattern of production, or production curve, which will indicate the volumes of gas and gas liquids produced each year during the productive life of the leases involved. This involves not only the volumes of gas and liquids produced in a given year, but the number of years over which production occurs. Unfortunately the record on production curves is not very helpful. The record contains various production curves which are based primarily upon estimate and judgment. These curves assume that gas and gas liquids are produced contemporaneously. Exhibit No. 42 of witness Spain and Exhibit 252 of witness Fraser both contain illustrative 37 year production schedules for non-associated gas.

Exhibit 146 of witness Roseman (schedule 10) sets forth a dual production schedule having separate rates of production for gas and for liquids, with liquids being produced at a faster rate than gas. This schedule is based upon certain production data contained in Exhibit 115 in a proceeding previously before the Commission entitled *Gulf Oil Corp.*, Docket No. G-9520. This exhibit sets forth typical production curves for crude oil and condensate (combined), dissolved and associated gas, and non-associated gas, relat-

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able to the operations of Gulf Oil Corp. In Exhibit 116 witness Roseman uses the figures for combined production of crude oil and condensate as a measure of the production of condensate. Since these production figures include crude oil as well as condensate, the producers contend they are unrepresentative of condensate production from gas well gas leases, and therefore invalid as a measure of that production. While the liquids portion of the Gulf curve may not describe typical condensate production with ultimate precision, it is equally clear that condensate production is not bound by the relatively slow rate of

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production for non associated gas. The Gulf curve shows non associated gas production in the 37th year, but *no* liquids production, neither crude oil *nor condensate*, past the 25th year. While the need for better data on this subject is clear, we believe the dual production curve taken from the Gulf proceeding (and in this record as Schedule 10 of Item II by Reference), provides a reasonably reliable estimate of the production of gas and gas liquids (condensate) from non-associated gas leases, and it will be employed herein to establish timing parameters for revenue receipts. Since the record discloses no proper justification for the adjustments made to the non-associated gas portion of this schedule in Exh. 116 (schedule 10), it will be employed in its original form.

Another important aspect of our DCF-Project analysis is the treatment of Federal income taxes. We have attempted to treat taxes on a realistic basis, conforming as closely as possible to the applicable tax laws as applied to the project model. The first step is to determine the amount of deductions for tax purposes. Total accounting charges (deduc-

tions from gross revenue) are comprised of the following elements: immediate write offs, amortization, depreciation, and depletion. Immediate tax write offs cover dry holes and other exploration costs. They are written off in the year incurred. Also written off in the year incurred are intangible drilling costs (IDC). We have estimated IDC to be 70 percent of successful well costs, based on Exhibit 252, sheet 5. (See also Exhibit 116, Schedule 2).

Amortization applies to the write off of unsuccessful leasehold investment cost. We have assumed that 75 percent of acquired leases ultimately prove to be unproductive, based on witness Fraser's Exhibit 252, sheet 5. Therefore 75 percent of lease acquisition costs are to be written off. We have timed the amortization of these unsuccessful or unproductive leasehold investments according to the incurrence of dry hole costs. This method conforms to the standard industry practice, and is the method used by witness Fraser (Exh. 252, sheet 5). However, Fraser assumed that

lease surrenderings are, on the average, two years later than the incidence of related dry hole expense. (278 [illegible]2732) We cannot accept this additional two year lag without a more adequate basis than is provided by the present record. Exhibit 252 (sheet 5) indicates that 50 percent of lease acquisition costs were incurred by 1957, but 50 percent of the abandonments were not written off until 1962. This indicates roughly an average of five years between lease expenditures and abandonment for unsuccessful leases. Considering the fact that the primary term of the ordinary oil and gas lease is five years, it would be unreasonable to assume that the *average* unproductive lease is written off a full five years after acquisition.

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Depreciation charges are applicable to Other Production Facilities and the remaining 30 percent of successful well costs. These costs relate to the tangible assets associated with successful wells. They are initially capitalized and depreciated during the course of production. Timing (or distribution) of the depreciated charges is determined on a unit-of production basis as measured by total revenue.

Depletion charges are customarily evaluated in terms of percent of gross income (or revenue). Producer witness Miller utilized a 26 percent effective depletion rate for federal income tax purposes (Exh. 167), as did Staff witness Spain (Exh. 12). The Hunt Group and Superior Oil Co. take exception to the 26 percent rate, claiming that as a result of certain amendments to the applicable tax laws which restrict the aggregation of properties, the effective depletion rate is no more than 24 percent. However, the President's 1963 tax message, upon which Dr. Spain based his use of the 26 percent rate is careful to point out that the amount of depletion shown therein (table 6) is understated since the tax returns as originally filed did not include the final aggregation of properties. "These aggregations increased the depletion allowed and reduced the corporate income tax liability." (page 291). Moreover, the effective depletion rate is the result of both percentage (statutory) depletion and cost depletion. Cost depletion is not subject to statutory limitations, and may exceed 27½ percent, which is the maximum percentage depletion allowed by law. We believe the present record indicates an effective depletion rate of at least 26 percent.

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The total accounting charges for each year are added to

current production costs (if any) for that year, and this total is deducted from gross revenue. The result is taxable income. In computing tax liability, we have used a tax rate of 48 percent.

As a result of these tax considerations, the project reflects an alternative tax liability on liquid and gas. However, these tax liabilities arise in the mature years of producing properties, at a time when offsetting tax losses are being generated on new projects. In the net this has led the industry to no taxes on production. If all exploration for new reserves were to cease, and existing properties were produced to depletion, the industry as a whole would reach the point of incurring actual tax liabilities on its gas producing operations. However, the natural gas industry is an ongoing and expanding operation, and the large tax write-offs for successful exploration expenditures, intangible drilling costs, etc., incurred during the exploratory effort and earlier years of the lease production cycle are sufficient to offset any income tax liability which would otherwise be imposed on maturing productive leases.

It should be noted that the project overstates theoretical tax liability since interest on long term debt has not been included as an accounting charge. The present record does not provide the basis for determining this item in a project analysis. To do so would require an allocation of overall company debt to the production function, and a determination of interest charges applicable to the allocated debt. None of the project models in this proceeding reflect interest charges for tax purposes.

[illegible] appears to be of relatively minor importance [illegible] producing industry historically has relied primary

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on equity capital and retained earnings rather than long term debt to finance its operations.[3] Nevertheless,

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to the extent interest expense actually incurred, the tax liability reflected in the project is correspondingly overstated, and the rate of return is understated. In other words, our project indicates an 8 percent true yield under conditions of totally debt free operation. Since the industry in fact utilizes some debt capital, and thus incurs interest expense, it could expect to earn somewhat more than the demonstrated 8 percent."

Current production costs refer to Production Operating Expenses, Royalty, and Production Taxes. These costs are distributed in the project on a unit of production (total revenue) basis.

We have made no allowance in the project for working capital. No party recommended such an allowance, and we conclude none is warranted.

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TRUE-YIELD RATE OF RETURN

In order to compare our DFC Project model (Appendix C) with the results of the new gas well gas costing, it is necessary to evaluate the adequacy of the 8 percent rate of return generated by the project. This 8 percent return is termed a "true-yield" since it purportedly represents the

[3] Long-term debt comprises approximately 15 percent of total capitalization for integrated producers. Exh. 21, Sch. 2; Exh. 65, Sch. 18; Exh. 121, page 48. Estimates of long-term debt for non-integrated producers vary widely, ranging in the exhibits from 1 percent to 18.6 percent, depending on the sample of companies used by the rate of return witnesses.

yield on the "true" economic investment devoted to finding and producing gas-well gas; as distinguished from a return allowed on book capital.

The three witnesses who testified on this subject used a cost of capital approach in estimating the appropriate true yield rate of return required by the industry. In doing so they were primarily concerned with the cost of equity capital, since producers historically have relied primarily on equity and retained earnings rather than debt in financing their oil and gas operations. The witnesses were in virtual agreement on the method to be used to estimate the cost of equity. Producer witness Ezra Solomon stated ". . . the appropriate measure of the cost of equity capital is the capitalization rate at which the expected stream of cash receipts per unit of equity capital is equal to the market price per unit." (TR2590). MGD witness David A. Kosh stated, ". . . the cost of equity is the capitalization rate which will equate the current market price with the present value of all future dividends." (TR3760). Staff witness Harold L. Spain's testimony and methodology indicate his agreement with this definition of the cost of equity. Therefore, to find the cost of equity capital for a given company it is necessary under the proposed method to (1) estimate the dividends to be received in the future from a share of the company's stock, and (2) determine by means of mathematical computation the discount rate at which the present worth of those future dividends is equal to the current market price per share of stock. Where future dividends are estimated to grow at a uniform rate, the cost of capital is equal to the sum of the rate of growth in dividends plus the current rate of dividends. In other words, if a stock were selling at 100 dollars per share, paying a current dividend of 3 dollars per share, and future dividends were estimated to grow at 5 percent per

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year, the cost of equity would be 8 percent. This short-hand formula can be applied, however, only where future dividend growth is projected at a uniform rate. With these considerations in mind, we turn to a more detailed examination of the true-yield rate of return evidence in the present record.

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Witness Ezra Solomon, testifying for the producer respondents, based his true-yield recommendations upon an analysis of pertinent data for 16 domestic non-integrated producing companies covering the period 1947-62. (Exhibit 73). First he calculated the actual cash dividends paid by the 16 companies from 1947 through 1962. These payments included liquidating dividends related to 8 sample companies which were liquidated before the end of 1962. He then calculated the dividend growth rate for the 8 unliquidated companies during the same period. The result was a growth rate of 8.08 percent per year. He then used this growth rate of 8.08 percent to project future dividends for the remaining 8 companies. That is, he assumed that dividends for these 8 companies would grow at a compound rate of 8.08 percent to infinity. He then determined the cost of equity capital for all years 1947-62 for all 16 sample companies by calculating the capitalization or discount rate which would equate the present value of the actual and projected future dividends with the average market value of the companies' equity in the applicable year. For the period as a whole the median value of the estimated cost of equity capital was 11 percent, and its arithmetic average was 12 percent. From this Dr. Solomon concluded the minimum cost of equity capital for the oil and gas producing industry lies between 10 and 12 percent, with 11 percent being the single best estimate. Based on an illus-

trative capital structure comprised of 90 percent equity and 10 percent long-term debt, with an equity cost of 11 percent and a debt cost of 4.5 percent, he calculated an overall rate of return of 10.3 percent.

We note initially that Dr. Solomon based his recommendations on the estimated equity cost for all 16 sample companies, including those companies liquidated before the end of 1962. These liquidations resulted in large liquidating dividends in years 1956, 1958, 1961, and 1962. In fact it appears that liquidating dividends were more than double the total amount of ordinary dividends paid during the entire period. We do not say that it was wrong in theory to include the 8 liquidated companies in the equity cost computations, but we do think their inclusion was an unnecessary and complicating factor which may have tended to distort the results simply because of the number of companies being liquidated (50 percent of the sample) and the large proportion of total dividends resulting from liquidation. In estimating the cost of equity we are dealing essentially with the reasonable expectations of the investing public or of the marketplace, and we do not think investors customarily expect or anticipate a termination of their investment through liquidation.

Although it was not calculated as such, the equity cost for the 8 unliquidated companies appears on the face of Exhibit 73. The actual and projected dividends are growing at an annual and uniform rate of 8.08 percent (Schedule 3). The current dividend yield for the 8 unliquidated companies is shown in Schedule 4. Dividends for the entire period averaged 2.25 percent; dividend yield for the most recent 10 year period, 1953-1962 averaged 1.76 percent. It

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appears therefore, that accepting Dr. Solomon's projection of dividend growth, and adding to this the current yield, the indicated equity cost for the 8 unliquidated companies was approximately 10 percent.

A more crucial factor in Dr. Solomon's approach was his projection of future dividend growth at the compound rate of 8.08 percent derived from the past record of dividend growth between 1947 and 1962. Of course there is no way of knowing what future dividends will in fact be, nor is there any precise way to determine what investors expect or demand in this regard when they purchase equities. As observed by Dr. Solomon, "There is no way of proving or disproving that the growth pattern I have selected will in fact occur. All a projection can claim is that it is the most reasonable one available on the basis of existing evidence. Unfortunately it is not possible to completely by-pass the need for some projection of future expectations in arriving at any measure of the cost of equity capital." (TR2598-99).

We do not believe that the ordinary investor in oil and gas producing companies can realistically expect or demand a growth rate in dividends of 8 percent per year for an unlimited period of time. This growth rate in dividends is twice as great as that for Standard and Poor's industrials over the same period. (Exh. 73, Schedule 6). Such a high growth rate may be anticipated and achieved over relatively short periods, but is unlikely to be maintained indefinitely. The growth in total gas consumption in the United States during the period 1946-1962 averaged 8.1 percent. (Exhibit 68-A, Schedule 3). We observe that his figure closely approximates the growth in dividends observed by Dr. Solomon over the same period. However, we have no reason to expect, and witness Solomon gives no reason to expect, consumption of oil or gas to grow faster than 4%

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over the long run.[4] In our judgment the projected growth rate of 8 percent to infinity is overly optimistic and cannot be supported on this record or by our judgment. As a result we conclude that Dr. Solomon's estimates tend to overstate the industry's cost of attracting equity capital for employment in and gas producing operations.

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In his testimony and related Exhibit 147, staff witness Harold L. Spain adopted the same conceptual approach in estimating the cost of equity, but made certain crucial changes in applying the rationale. First Dr. Spain examined the growth in dividends for the 6 companies in Dr. Solomon's sample which were still in existence at the time his testimony and exhibit were prepared, using the 10 year period 1953-1962. The result was an estimated annual growth rate of 9.3 percent. However Dr. Spain concluded it would not be proper to anticipate that such a relatively high growth rate could continue indefinitely into the future. Therefore, in estimating future dividend growth for the sample companies, Dr. Spain adopted a logistic or "S" curve, extending over a period of 25 years, 1962-1987. Dividends during the first 13 years were projected at the observed rate of 9.3 percent. After the 13th year, growth was tapered off symetrically for another 12 years until 1987. After 1987 all growth was curtailed, and the dividend level established in 1987 was projected indefinitely. Using this pattern of estimated dividends, witness Spain calculated that their present worth in 1962 was equal to the average 1962 market value of the 6 company stock sample when discounted at the compound rate of 6.5 percent. He concluded that the cost of equity capital to the domestic non-inte-

[4] *Cf.* Exh. 262, excluded by the Examiner, marked "offer of proof".

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grated producers was no greater than 6.5 percent, providing the 6 company sample was representative.

As a check on representativeness, witness Spain made a separate calculation of the cost of equity to a group of 8 large integrated producers. In this case dividends on the sample of stocks were found to have been growing at a linear rather than a compound rate. Therefore, in projecting future dividend growth, witness Spain continued the linear growth for 25 years, after which growth was curtailed and the 1987 dividend level maintained. In this instance the 1962 present value of the future dividends equated with the average 1962 price of the stock sample when discounted at 6.75 percent. On this basis, Dr. Spain estimated that the industry as a whole encountered an equity cost in 1962 no greater than 6.75 percent.

In considering this evidence, we note initially that the equity cost was determined only for one year, 1962, whereas Dr. Solomon calculated the cost for each year 1947-1962, and based his recommendations on the average for the entire period. We thing it is preferable to make calculations for more than one year, since the results in any given year are determined in large part by the average price of the given stock sample in that year. In other words, where the equity cost is estimated as of 1962, the appropriate discount factor (or true-yield rate) is that which will equate the present value of future dividends with the average 1962 market value of the stock sample. When calculations are made for several different years,

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there is less likelihood of bias resulting from unusually high or low stock prices in a given year. We do not say that 1962 was such a year, or that the average 1962 prices

of the stock sample used by Dr. Spain was unrepresentative. We simply observe that making separate calculations for other years might well tend to reduce the margin for error by making the ultimate conclusions less dependent on stock prices in any single year.

The second factor determining Dr. Spain's estimate of equity cost is his projection of future dividends. We think the concept employed by Dr. Spain to estimate potential dividends is entirely rational. That is to say we think it is reasonable to assume that profits earned by the industry from the production and sale of oil and gas, and the dividends paid therefrom, will continue to grow until such time as the industry as a whole reaches a mature state of development and becomes static, due to the ultimate depletion of oil and gas reserves, due to the use of fuel sources other than oil and gas, or for a number of other reasons. The problem is to estimate the rate or rates of future growth, and the period over which this growth will occur before the onset of static conditions. We believe it is reasonable to assume that future dividend growth for the industry will follow a pattern such as that suggested by Dr. Spain. We think such a pattern is clearly more realistic than the projection of unlimited exponential growth such as that adopted by witness Solomon. It is far more difficult, however, to determine or predict the time period over which the logistic pattern will evolve. Our principal difficulty is not with the initial 25 year period of dividends projected by Dr. Spain, but rather with the fact that after 25 years growth is entirely curtailed. In our opinion it would not be proper to assume that by 1987 the industry as a whole will have reached the point where future growth is unlikely. It should be noted in this connection that the more remote future dividends are in time, the less they influence the current cost of equity capital. This is because the present

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value of future dividends varies inversely with the postponement of their realization. In other words the present value of a $1 dividend to be received in 1970 is greater than that of a $1 dividend to be received in 1980. For this reason Dr. Spain's curtailment of growth after 1987 affects his 1962 cost of equity estimate to a far lesser extent than might otherwise be expected. Nevertheless, we believe the estimate of future dividend expectations adopted by Dr. Spain is clearly conservative, and produces an estimated cost of equity which may be somewhat lower than that actually incurred by producers.

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In his testimony and Exhibit 124, MGD witness David A. Kosh employed two different methods to estimate the cost of equity to oil and gas producers. The first, which he termed the "Present Value Method" is conceptually identical to the method followed by witnesses Solomon and Spain. The second method involved the analysis of earnings-price ratios. We will here be concerned only with the present value method since we agree with Mr. Kosh that, in the context of these proceedings, the earnings-price method is relatively less reliable as a measure of equity cost to this industry. Mr. Kosh based his equity cost estimates on two groups of companies. The first consisted of 9 domestic, non-integrated producers, and the second consisted of 22 large integrated companies. In analyzing the group of 9 producers, Mr. Kosh first computed the earnings per share for the years 1946-62, and plotted the results. For each company he then chose a period which in his judgment represented the most reliable trend in earnings per share. The periods were not the same in every case, although the periods were at least 10 years in length in all cases. From this he determined the annual rate

of growth in earnings per share. The average growth rate for the entire 9 company sample was 4.4 percent per year. Next, he calculated the average dividend yield for each company for the period 1955-62. The average for all 9 companies was 3.4 percent. Mr. Kosh projected future dividends on the basis of the growth in earnings per share of 4.4 percent. In using earnings growth rather than dividend growth, he observed that in the long run dividends must flow from earnings, and concluded that long run growth in earnings per share provides a better picture of what future dividend growth would be than a direct statistical analysis of past dividends. With future dividends estimated to grow at a rate of 4.4 percent per year, and with a current yield of 3.4 percent, the cost of equity for the 9 company sample was 7.8 percent. The comparable figures for the group of integrated producers were a 3.9 percent growth rate in estimated future dividends, based on past growth in earnings per share, and a 3.9 percent current yield, for an identical total of 7.8 percent.

To these costs witness Kosh made an upward adjustment to allow for financing costs and "pressure". Financing costs refer to the underwriting and corporate costs incurred in selling common stock, and "pressure" refers to the fact that the offer

of additional stock may exert a downward pressure on the market price of the stock. To allow for these considerations, Mr. Kosh increased the current yield component of the cost estimate by 15 percent.[5] This resulted in an equity cost of 8.3 percent for the 9 company sample, and 8.4 percent for the 22 company sample. Ultimately, Mr. Kosh recommended 10 percent as the cost of equity in order to provide an "extra margin of safety".

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The principal difference in methodology between Mr. Kosh and witnesses Solomon and Spain is that in estimating future dividends Mr. Kosh used as a guide the past growth in earnings per share rather than past growth in dividends paid. We do not think this was improper. It seems clear that in the long run dividends must flow from earnings. Therefore dividends per share cannot in the long run grow at a faster rate than earnings per share.

The evidence reflects a very real and serious conflict regarding the growth experienced by non-integrated producers in past year. Witness Solomon calculated dividend growth for the period 1947-62 at approximately 8 percent, and witness Spain calculates dividend growth for the period 1953-62 at approximately 9 percent. But witness Kosh calculates growth in earnings for the period roughly 1950-1962 at only 4.4 percent. It appears that not all of these figures can be representative of the non-integrated producers as a group, since it is highly improbable that dividends could have been growing at a rate almost double that of earnings per share. The reasons undoubtedly are to be found in the differences in samples and differences in time periods utilized by the several witnesses. We also note that the results obtained by witnesses Solomon and Spain reflects a weighting of individual company growth rates based on relative company size, whereas Mr. Kosh took a pure average of the growth rates established by the companies in his sample. We think it would be more helpful if for each sample the growth rate in dividends and the growth rate in earnings are both computed, since one growth rate serves as a check against the other. That is to say we think dividend growth and earnings growth for a given sample of companies over a given time period

[5] See generally *Phillips Petroleum Co.*, Opinion No. 538, 24 FPC 537, 571-72 (1960).

should be approximately the same unless there were significant changes in the pay out ratio. Moreover if the payout ratio were changing over the observation period, we think past earnings growth would be a better indication of future dividend growth than would the record of past dividends. With these considerations in mind, we think the growth rate in earnings, as measured by witness Kosh is entitled to full consideration in projecting the growth rate of future dividends for purposes of estimating the cost of equity capital.

Since the method advocated by the true yield proponents in this proceeding to determine the cost of equity capital depends in large part on the expectations of investors, as reflected by the prices they are willing to pay for equities in relation to their expected dividends from such equities, judgment must necessarily play a large part. In future cases the parties may find a convenient and acceptable method of translating a conventional rate base into a properly timed expenditure schedule for a DCF Project study. In that event, the true yield rate of return could be more readily compared to the results achieved under the more accepted, time tested methods. In any event, we have reviewed the evidence in the present record, as outlined above, with emphasis on the past rates of dividend and earnings growth, and current yields and have attempted to translate these figures not only into a general estimate of future dividend growth, but also into an estimate of reasonable investor expectations. It is our conclusion that on a true yield basis the cost of equity to the producers of oil and gas is in the range of 7.5 to 9 percent.

In calculating the appropriate overall true-yield rate of return, we will utilize a capital structure composed of 15

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percent long term debt, and 85 percent equity,* and an equity cost of 8 percent. With respect to the cost of debt, witness Solomon recommended 4.5 percent, while witness Kush recommended 4.3 percent for debt outstanding in 1982, and 5 percent for additional debt. In view of subsequent increases in debt interest rates, we will employ an illustrative overall imbedded debt cost of 5 percent. At an overall 8 percent true yield rate of return, the rate of return on equity would

be 8.53 percent. Our DFC Project model yields an overall return of 8 percent, thus affording a return on equity of 8.5 percent. In fact, the model yields more than the stated 8 percent overall or 8.5 percent on equity because, as we have stated previously, certain costs used in the model are exaggerated and the return is consequently understated. We conclude that the project yields an adequate return, and in our judgement confirms the validity and accuracy of our new gas well gas cost determination.

The overall 8 percent yield for producers exceeds the overall rate of return allowed pipeline companies. However, the 8 percent implies about 8.5 percent on producer equity whereas pipeline equity has typically been in the range of 9 to 11 percent. In comparing these returns on equity we again note that the return on producer equity would actually be higher than 8.5 percent even accepting the proposed DCF approach, higher because our analysis exaggerates certain costs *e.g.* failed to reflect interest as a tax deduction, thereby exaggerating taxes and thus understates the rate of return.

Furthermore, in making these comparisons, we must con-

* Page 50, *supra*.

sider that the pipelines rely to a large extent on long term debt to finance their operations, whereas producers rely primarily on equity capital. The return on equity is determined by the cost of debt in conjunction with the debt-equity ratio. For example, assuming debt costs of 5 percent, if an overall rate of return of 6.5 percent is allowed a company with a capital structure composed of 15 percent debt and 85 percent equity, the return on equity is approximately 6.8 percent. However, if the capitalization is 60 percent debt and 40 percent equity, the return on equity is 8.75 percent. If the producers and pipelines had the same debt-equity ratio, the higher overall return for producers would of course give them a higher return on equity than pipelines.

In any event, an overall true-yield of 8 percent in the DCF format is appropriate, for reasons stated above, whatever the return allowed pipelines. Respondents' own witness Solomon recognized 10 percent true yield as reasonable for producer equity. This high figure is based in part on his undue expectations for growth. Correcting his recommendation of 10 to 12 percent true-yield to reflect 6 rather than 8 percent growth would lead to figures of 9 to 11 percent. Our cost allowances are consistent with about 9 percent true-yield on producer equity.

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APPENDIX C

PROJECT-ACCOUNTING CALCULATION OF THE COST OF WELLHEAD PRODUCTION OF NON-ASSOCIATED GAS

Table 1: Indication That a Price of 18.29¢ per Mcf Will Cover All Costs Including 8.0 - Percent Return Incurred in Producing 1,000,000 Mcfs of Non-associated Gas Plus Attendant Condensate and Plant Liquids

Year	Gas Prod. % of Ult.	Liq. Prod. % of Ult.	Gas Revenue ($)	Liq. Revenue ($)	Total Gas and Liq. Revenue ($)	Total Gas and Liq. Rev. enue (%)	Investment Outlay ($)	Current Prod. Cost ($)	F.-I.-T. Lia. ($)	Net Cash Flow ($)	Discounted Worth at 8% ($)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1951											
1952							3,376		-1,351	-2,025	-4,048
1953							725		- 346	- 379	- 701
1954							845		- 469	- 376	- 644
1955							526		- 204	- 322	- 511
1956							1,590		- 563	-1,027	-1,509
1957							1,924		- 709	-1,215	-1,653
1958							3,641		- 741	-2,900	-3,653
1959							6,421		-2,098	-4,323	-5,042
1960							8,612		-3,606	-5,006	-5,406
1961	3.14	7.60	5,743	3,126	8,869	3.96	13,935		-4,807	-9,128	-9,128
1962	3.53	7.60	6,456	3,126	9,582	4.28	15,933	3,242	-5,026	-5,280	-4,889
1963	3.90	7.60	7,133	3,126	10,259	4.58	7,417	3,504	-1,413	274	235
1964	4.27	7.60	7,810	3,126	10,936	4.88	3,095	3,750	573	2,841	2,255
1965	4.61	7.60	8,432	3,126	11,558	5.16	2,535	3,996	854	3,551	2,610
1966	4.61	7.60	8,432	3,126	11,558	5.16	1,832	4,225	1,185	4,316	2,937
1967	4.61	7.60	8,432	3,126	11,558	5.16		4,225	1,958	5,375	3,387
1968	4.61	6.87	8,432	2,826	11,258	5.03		4,225	1,958	5,375	3,136
1969	4.61	5.64	8,432	2,320	10,752	4.80		4,119	1,906	5,233	2,827
1970	4.61	4.74	8,432	1,950	10,382	4.63		3,930	1,822	5,000	2,501
1971	4.61	4.09	8,432	1,682	10,114	4.51		3,791	1,762	4,829	2,237
1972	4.61	3.56	8,432	1,464	9,896	4.42		3,693	1,715	4,706	2,018
1973	4.61	3.13	8,432	1,288	9,720	4.34		3,619	1,676	4,601	1,827
1974	4.61	2.75	8,432	1,131	9,563	4.27		3,554	1,647	4,519	1,662
1975	4.61	2.43	8,432	1,000	9,432	4.21		3,496	1,620	4,447	1,514
								3,447	1,598	4,387	1,383

(continued)

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(Table 1 concluded)

Year	Gas Prod. % of Ult.	Liq. Prod. % of Ult.	Gas Revenue ($)	Liq. Revenue ($)	Total Gas and Liq. Revenue ($)	Total Gas and Liq. Revenue (%)	Investment Outlay ($)	Current Prod. Cost ($)	F.-I.-T. Lia. ($)	Net Cash Flow ($)	Discounted Worth at 8% ($)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1976	4.61	2.15	8,432	885	9,317	4.16		3,406	1,579	4,332	1,265
1977	4.61	1.90	8,432	782	9,214	4.11		3,365	1,563	4,286	1,159
1978	3.92	1.69	7,169	695	7,864	3.51		2,874	1,333	3,657	915
1979	3.35	1.50	6,127	617	6,744	3.01		2,465	1,143	3,136	727
1980	2.84	1.35	5,194	555	5,749	2.57		2,104	972	2,673	573
1981	2.43	1.21	4,444	497	4,941	2.20		1,801	840	2,300	457
1982	2.06	1.09	3,768	448	4,216	1.88		1,539	715	1,962	361
1983	1.76	.99	3,219	407	3,626	1.62		1,326	614	1,686	287
1984	1.49	.90	2,725	370	3,095	1.38		1,130	525	1,440	227
1985	1.27	.81	2,323	333	2,656	1.18		966	483	1,237	181
1986	1.06		1,939		1,939	0.87		712	326	901	122
1987	.92		1,682		1,682	0.75		614	286	782	98
1988	.78		1,426		1,426	0.64		524	240	662	77
1989	.65		1,189		1,189	0.53		434	202	553	59
1990	.55		1,006		1,006	0.45		369	170	467	46
1991	.47		859		859	0.38		311	147	401	37
1992	.41		750		750	0.33		270	129	351	30
1993	.35		640		640	0.29		237	107	296	23
1994	.29		530		530	0.24		197	88	245	18
1995	.25		457		457	0.20		164	79	214	14
1996	.20		366		366	0.16		131	63	172	11
1997	.18		329		329	0.15		123	54	152	9
Total	100.00	100.00	182,900	41,132	224,032	100.00	72,407	81,878	40,369	59,378	41

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PROJECT-ACCOUNTING CALCULATION OF THE COST OF WELLHEAD PRODUCTION OF NON-ASSOCIATED GAS

Table 2: Estimated Investment Outlays Expended in Finding and Developing 1,000,000 Mcfs of Non-Associated Gas Plus Attendant Condensate and Plant Liquids (dollars)

Year	Total	Lease acquisition Costs	Other exploration Costs	Dry-hole Costs	Successful-Well Costs	Other Production Facilities Costs
	(1)	(2)	(3)	(4)	(5)	(6)
1951	3,376	391	1,364	578	916	127
1952	725	46	574	105	-	-
1953	845	69	272	504	-	-
1954	526	127	336	63	-	-
1955	1,590	216	829	13	467	65
1956	1,924	475	1,298	111	35	5
1957	3,641	2,012	1,065	167	348	49
1958	6,421	1,104	1,695	571	2,679	372
1959	8,612	766	1,715	2,579	3,119	433
1960	13,935	1,492	2,642	1,714	7,101	986
1961	15,933	428	2,187	4,104	8,090	1,124
1962	7,417	409	1,116	2,545	2,939	408
1963	3,095	134	606	475	1,651	229
1964	2,535	91	366	558	1,335	185
1965	1,832	35	345	476	857	119
Total	72,407	7,795	16,410	14,563	29,537	4,102

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PROJECT-ACCOUNTING CALCULATION OF THE COST OF WELLHEAD PRODUCTION OF NON-ASSOCIATED GAS

Table 3: Estimation of Federal Income Tax Liability Incident to the Production of 1,000,000 Mcfs of Non-Associated Gas Plus Attendant Condensate and Plant Liquids (dollars)

Year	Revenues	Current Production Costs	Accounting Charges	Taxable Income	Federal Income Tax Liability
	(1)	(2)	(3)	(4)	(5)
1951			2,815	- 2,815	-1,351
1952			721	- 721	- 346
1953			978	- 978	- 469
1954			424	- 424	- 204
1955			1,174	- 1,174	- 563
1956			1,478	- 1,478	- 709
1957			1,543	- 1,543	- 741
1958			4,370	- 4,370	-2,098
1959			7,512	- 7,512	-3,606
1960			10,015	-10,015	-4,807
1961	8,869	3,242	16,098	-10,471	-5,026
1962	9,582	3,504	9,438	- 3,360	-1,613
1963	10,259	3,750	5,316	1,193	573
1964	10,936	3,996	5,160	1,780	854
1965	11,558	4,225	4,865	2,468	1,185
1966	11,558	4,225	3,253	4,080	1,958
1967	11,558	4,225	3,253	4,080	1,958
1968	11,258	4,119	3,169	3,970	1,906
1969	10,752	3,930	3,026	3,796	1,822
1970	10,382	3,791	2,921	3,670	1,762
1971	10,114	3,693	2,847	3,574	1,715
1972	9,896	3,619	2,786	3,491	1,676
1973	9,720	3,554	2,735	3,431	1,647
1974	9,563	3,496	2,692	3,375	1,620
1975	9,432	3,447	2,655	3,330	1,598

(continued)

4485408

(Table 3 concluded)

Year	Revenues	Current Production Costs	Accounting Charges	Taxable Income	Federal Income Tax Liability
	(1)	(2)	(3)	(4)	(5)
1976	9,317	3,406	2,622	3,289	1,579
1977	9,214	3,365	2,593	3,256	1,563
1978	7,864	2,874	2,213	2,777	1,333
1979	6,744	2,465	1,898	2,381	1,143
1980	5,749	2,104	1,619	2,026	972
1981	4,941	1,801	1,390	1,750	840
1982	4,216	1,539	1,187	1,490	715
1983	3,526	1,326	1,021	1,279	614
1984	3,095	1,130	871	1,094	525
1985	2,656	966	747	943	453
1986	1,939	712	547	680	326
1987	1,682	614	473	595	286
1988	1,426	524	402	500	240
1989	1,189	434	335	420	202
1990	1,006	369	283	354	170
1991	859	311	241	307	147
1992	750	270	211	269	129
1993	640	237	181	222	107
1994	530	197	150	183	88
1995	457	164	128	165	79
1996	366	131	103	132	63
1997	329	123	93	113	54
Total	224,032	81,878	120,552	21,602	10,369

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PROJECT-ACCOUNTING CALCULATION OF THE COST OF WELLHEAD PRODUCTION OF NON-ASSOCIATED GAS

Table 4: Total Accounting (Non-Cash) Charges Allowable for Income Tax Purposes on the Investment Outlays Pertinent to Producing 1,000,000 Mcfs of Non-Associated Gas Plus Attendant Condensate and Plant Liquids (dollars)

Year	Total Accounting Charges	Immediate Write-offs	Amortization	Depreciation	Depletion
	(1)	(2)	(3)	(4)	(5)
1951	2,815	2,583	232		
1952	721	679	42		
1953	978	776	202		
1954	424	399	25		
1955	1,174	1,169	5		
1956	1,478	1,433	45		
1957	1,543	1,476	67		
1958	4,370	4,141	229		
1959	7,512	6,477	1,035		
1960	10,015	9,327	688		
1961	16,098	11,954	1,648	513	1,983
1962	9,438	5,718	1,022	555	2,143
1963	5,316	2,237	191	594	2,294
1964	5,160	1,859	224	632	2,445
1965	4,865	1,421	191	669	2,584
1966	3,253			669	2,584
1967	3,253			669	2,584
1968	3,169			652	2,517
1969	3,026			622	2,404
1970	2,921			600	2,321
1971	2,847			585	2,262
1972	2,786			573	2,213
1973	2,735			562	2,173
1974	2,692			554	2,138
1975	2,655			546	2,109

(continued)

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(Table 4 concluded)

Year	Total Accounting Charges	Immediate Write-offs	Amortization	Depreciation	Depletion
	(1)	(2)	(3)	(4)	(5)
1976	2,622			539	2,083
1977	2,593			533	2,060
1978	2,213			455	1,758
1979	1,898			390	1,508
1980	1,619			333	1,286
1981	1,390			285	1,105
1982	1,187			244	943
1983	1,021			210	811
1984	871			179	692
1985	747			153	594
1986	547			113	434
1987	473			97	376
1988	402			83	319
1989	335			69	266
1990	283			58	225
1991	241			49	192
1992	211			43	168
1993	181			38	143
1994	150			31	119
1995	128			26	102
1996	103			21	82
1997	93			19	74
Total	120,552	51,649	5,846	12,963	50,094

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PROJECT-ACCOUNTING CALCULATION OF THE COST OF WELLHEAD PRODUCTION OF NON-ASSOCIATED GAS

Table 5: Investment Outlays Written Off Immediately for Federal Income Tax Purposes (dollars)

Year	Total Immediate Write-offs	Expenditures Written Off Related to		
		Other Exploration Costs	Dry-hole Costs	Successful Well Costs
	(1)	(2)	(3)	(4)
1951	2,583	1,364	578	641
1952	679	574	105	-
1953	776	272	504	-
1954	399	336	63	-
1955	1,169	829	13	327
1956	1,433	1,298	111	24
1957	1,476	1,065	167	244
1958	4,141	1,695	571	1,8
1959	6,477	1,715	2,579	2,1
1960	9,327	2,642	1,714	4,971
1961	11,954	2,187	4,104	5,663
1962	5,718	1,116	2,545	2,057
1963	2,237	606	575	1,156
1964	1,859	366	558	935
1965	1,421	345	476	600
Total	51,649	16,410	14,563	20,676

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(308,234)

308,234
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Sources and Derivations

Table 1, Columns

1 and 2: Pattern of production taken from Item II, Schedule 10.

Column 3: Total gas revenues for 1,000,000 Mcf computed at the price of 18.29 cents per Mcf. This $182,000 is distributed according to the percentages in Column 1.

Column 4: Total liquid revenues for 1,000,000 Mcf computed at 4.1132 cents per Mcf. This $41,132 is distributed according to the percentages in Column 2. The 4.1132 cents per Mcf figure is the 15.025 psi equivalent of 4.6105 cents per Mcf at 14.65 psi. The latter figure is made up of 3.30 cents allowed as net liquid credit; plus 0.49 cents and 0.07 cents to cover royalty on condensate and on plant liquids, respectively; plus 0.1565 cents to cover production tax at 5.0 percent on condensate.

Column 5: Column 3 plus Column 4.

Column 6: Column 5 translated to percentages.

Column 7: From Table 2, Column 1.

Column 8: These costs chargeable on a unit of production basis total 8.1878 cents per Mcf, a sum made up of 2.24 cents for royalty on gas, 2.30 cents for production tax on gas, 0.15 cents for regulatory expense on gas, 0.5025 cents for royalty on condensate, 0.0718 cents for royalty on plant liquids, 0.1544 cents for tax on

liquids, and 2.7691 cents for production operating expense. These last four figures are at the 15.025 psi equivalents of the 14.65 psi figures of 0.49, 0.07, 0.1505, and 2.70, respectively.

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— C-10 —
— ii —

Column 9: From Table 3, Column 5.

Column 10: Derived by subtracting from Column 5 figures the sum of the figures in Columns 7, 8 and 9.

Column 11: Derived by applying to the figures in Column 10 the appropriate compounded discount factors, taking 1960 as base or zero year.

Table 2: Figures on the total line are the product of 1,000,000 times the unit cost found allowable in each cost category as converted to a 15.025 psi pressure base. Distribution of these totals by years follows in each case the timing pattern presented in Producers witness Fraser's Exhibit No. 252, Sheet 5.

Table 3, Column 1: From Table 1, Column 5.

Column 2: From Table 1, Column 8.

Column 3: From Table 4, Comun 1.

Column 4: Derived by subtracting from the figures of Column 1 the algebraic sum of figures in Columns 2 and 3.

Column 5: Figures calculated at 48 percent tax rate.

Table 4, Column 1: Totals of Columns 2, 3, 4 and 5.

Column 2: From Table 5, Column 1.

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Column 3: Total is 75 percent of the lease acquisition outlay total in Column 2 of Table 2. Distribution is by the pattern set forth in Fraser's Exhibit No. 252, Sheet 5, after elimination of the 2-year lag.

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— C-11 —
— iii —

Column 4: Total represents 30 percent of successful well costs plus 100 percent of outlays for other production facilities. Distribution is by unit of production based on Table 1, Column 6.

Column 5: Depletion calculated at an average effective rate of 26 percent of gross production revenue to the working interest. Working interest equals 86 percent of Table 1, Column 5.

Table 5, Column 1: Total of Columns 2, 3 and 4.

Column 2: Written off 100 percent at time of expenditure. Timing based on Exhibit No. 252, Sheet 5.

Column 3: Written off 100 percent at time of expenditure. Timing based on Exhibit No. 252, Sheet 5.

Column 4: Written off 70 percent at time of expenditure. Timing based on Exhibit No. 252, Sheet 5.

Docket No. AR61-2, et al. DISCOUNTED CASH FLOW TEST OF THE DETERMINED COST OF WELLHEAD PRODUCTION OF NON-ASSOCIATED GAS

APPENDIX D
Sheet 1
D-1

Table 1: Indication that originally determined prod cer cost allowances will cover costs, including 12 percent return, incurred in producing non-associated gas plus attendant condensate and plant liquids.

Year	Gas Prod. Percent of Ultimate	Liquid Prod. Percent of Ultimate	Producer Gas Revenue	Producer Liquid Revenue	Total Producer Gas & Liquid Revenue	Total Producer Gas & Liquid Revenue	Investment Outlay	Current Production Costs	F.I.T Liability	Net Cash Flow	Discounted Present Worth at 12%
	(1)	(2)	$ (3)	$ (4)	$ (5)	% (6)	$ (7)	$ (8)	$ (9)	$ (10)	
1951							0.139832		-0.040860	-0.098972	-0.274459
1952							0.004484		-0.001970	-0.002514	-0.006225
1953							0.006764		-0.009467	0.002703	0.005976
1954							0.012388		-0.001176	-0.011212	-0.022130
1955							0.072876		-0.015536	-0.057340	-0.101050
1956							0.050296		-0.003240	-0.047056	-0.074043
1957							0.234860		-0.014565	-0.220295	-0.309492
1958							0.405112		-0.098494	-0.306618	-0.384622
1959							0.421000		-0.150642	-0.270358	-0.302801
1960							0.933936		-0.264833	-0.669143	-0.669143
1961	3.14	7.60	0.421074	0.250800	0.671874	4.02	0.940116	0.280998	-0.267371	-0.281889	-0.251681
1962	3.53	7.60	0.473373	0.250800	0.724173	4.33	0.366184	0.302667	-0.063331	0.118653	0.094590
1963	3.90	7.60	0.522990	0.250800	0.773790	4.63	0.196424	0.323637	0.023095	0.230634	0.164165
1964	4.27	7.60	0.572607	0.250800	0.823407	4.93	0.157148	0.344607	0.037219	0.284433	0.180757
1965	4.61	7.60	0.618201	0.250800	0.869001	5.20	0.098560	0.363480	0.059675	0.347306	0.197061
1966	4.61	7.60	0.618201	0.250800	0.869001	5.20		0.363480	0.096684	0.408837	0.207117
1967	4.61	7.60	0.618201	0.250800	0.869001	5.20		0.363480	0.096684	0.408837	0.184917
1968	4.61	6.87	0.618201	0.226710	0.844911	5.06		0.353694	0.093747	0.397470	0.160538
1969	4.61	5.64	0.618201	0.186120	0.804321	4.81		0.336219	0.089671	0.378431	0.136462
1970	4.61	4.74	0.618201	0.156420	0.774621	4.64		0.324336	0.085890	0.364395	0.117335
1971	4.61	4.09	0.618201	0.134970	0.753171	4.51		0.315249	0.083605	0.354317	0.101866
1972	4.61	3.66	0.618201	0.117480	0.735681	4.40		0.307560	0.081988	0.346133	0.088857
1973	4.61	3.13	0.618201	0.103290	0.721491	4.32		0.301968	0.080107	0.339416	0.077794
1974	4.61	2.75	0.618201	0.090750	0.708951	4.24		0.296376	0.079017	0.333558	0.068246
1975	4.61	2.43	0.618201	0.080190	0.698391	4.18		0.292182	0.077646	0.328563	0.060028
1976	4.61	2.15	0.618201	0.070950	0.689151	4.12		0.287988	0.076908	0.324255	0.052886
1977	4.61	1.90	0.618201	0.062700	0.680901	4.08		0.285192	0.075413	0.320296	0.046635
1978	3.92	1.69	0.525963	0.055770	0.581442	3.48		0.243252	0.066646	0.273544	0.035561
1979	3.35	1.50	0.449235	0.049500	0.498735	2.98		0.208302	0.055758	0.234675	0.027246
1980	2.84	1.35	0.380844	0.044550	0.425394	2.55		0.178245	0.047052	0.200097	0.020750
1981	2.43	1.21	0.325863	0.039930	0.365793	2.19		0.153081	0.040627	0.172085	0.015935
1982	2.06	1.09	0.276246	0.035970	0.312216	1.87		0.130713	0.034630	0.146873	0.012132
1983	1.76	0.99	0.236116	0.032670	0.268686	1.61		0.112539	0.029758	0.126389	0.009328
1984	1.49	0.90	0.199809	0.029700	0.229509	1.37		0.095763	0.025741	0.108005	0.007118
1985	1.27	0.81	0.170307	0.026730	0.197037	1.18		0.082482	0.021864	0.092691	0.005450
1986	1.06		0.142146		0.142146	0.85		0.059415	0.015851	0.066880	0.003511
1987	0.92		0.123372		0.123372	0.74		0.051726	0.013618	0.058028	0.002722
1988	0.78		0.104598		0.104598	0.63		0.044037	0.011385	0.049176	0.002060
1989	0.65		0.087165		0.087165	0.52		0.036348	0.009795	0.041022	0.001534
1990	0.58		0.077755		0.077755	0.44		0.030756	0.008288	0.034711	0.001159
1991	0.47		0.063027		0.063027	0.38		0.026562	0.006837	0.029628	0.000883
1992	0.41		0.054981		0.054981	0.33		0.023067	0.006056	0.025858	0.000688
1993	0.35		0.046935		0.046935	0.28		0.019572	0.005275	0.022088	0.000526
1994	0.29		0.038889		0.038889	0.23		0.016077	0.004494	0.018318	0.000388
1995	0.25		0.033525		0.033525	0.20		0.013980	0.003768	0.015777	0.000298
1996	0.20		0.026820		0.026820	0.16		0.011184	0.003014	0.012622	0.000213
1997	0.18		0.024138		0.024138	0.14		0.009786	0.002959	0.011393	0.000172
Total	100.00	100.00	13.410000	3.300000	16.710000	100.00	4.040000	6.990000	0.617280	5.062790	-.302747

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Sheet 2
D-2

A DISCOUNTED CASH FLOW TEST
OF THE DETERMINED COST OF WELLHEAD PRODUCTION OF NON-ASSOCIATED GAS

Table 2: Estimated investment outlays expended in finding and developing non-associated gas plus attendant condensate and plant liquids.

Year	Investment Outlays Total ¢ (1)	Lease Acquisition Costs ¢ (2)	Successful Well Costs ¢ (3)	Other Production Facilities Costs ¢ (4)
1951	0.139832	0.038152	0.089280	0.012400
1952	0.004484	0.004484	-	-
1953	0.006764	0.006764	-	-
1954	0.012388	0.012388	-	-
1955	0.072876	0.021052	0.045504	0.006320
1956	0.050296	0.046360	0.003456	0.000480
1957	0.234860	0.196156	0.033984	0.004720
1958	0.405112	0.107616	0.261216	0.036280
1959	0.421000	0.074632	0.304128	0.042240
1960	0.933976	0.145464	0.692352	0.096160
1961	0.940116	0.041724	0.788832	0.109560
1962	0.366184	0.039824	0.286560	0.039800
1963	0.196424	0.013072	0.160992	0.022360
1964	0.157148	0.008892	0.130176	0.018080
1965	0.098540	0.003420	0.083520	0.011600
Total	4.040000	0.760000	2.880000	0.400000

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A DISCOUNTED CASH FLOW TEST
OF THE DETERMINED COST OF WELLHEAD PRODUCTION ON NON-ASSOCIATED GAS

Table 3: Estimation of Federal Income Tax Liability incident to the production of non-associated gas plus attendant condensate and plant liquids.

Year	Revenues ¢ (1)	Current Production Costs ¢ (2)	Accounting Charges ¢ (3)	Taxable Income ¢ (4)	Federal Income Tax Liability ¢ (5)
1951			0.085125	-0.085125	-0.040860
1952			0.004104	-0.004104	-0.001970
1953			0.019722	-0.019722	-0.009467
1954			0.002451	-0.002451	-0.001176
1955			0.032366	-0.032366	-0.015536
1956			0.006751	-0.006751	-0.003240
1957			0.030344	-0.030344	-0.014565
1958			0.205195	-0.205195	-0.098494
1959			0.313837	-0.313837	-0.150642
1960			0.551736	-0.551736	-0.264833
1961	0.671874	0.280998	0.947898	-0.557022	-0.267371
1962	0.724173	0.302667	0.553446	-0.131940	-0.063331
1963	0.773790	0.323637	0.404038	0.048115	0.023095
1964	0.823407	0.344607	0.401260	0.077540	0.037219
1965	0.869001	0.363480	0.381199	0.124322	0.059675
1966	0.869001	0.363480	0.304096	0.201425	0.096684
1967	0.869001	0.363480	0.304096	0.201425	0.096684
1968	0.844911	0.353694	0.295910	0.195307	0.093747
1969	0.804321	0.336219	0.281288	0.186814	0.089671
1970	0.774621	0.324336	0.271348	0.178937	0.085890
1971	0.753171	0.315249	0.263744	0.174178	0.083605
1972	0.735681	0.307560	0.257312	0.170809	0.081988
1973	0.721491	0.301968	0.252634	0.166889	0.080107
1974	0.708951	0.296376	0.247956	0.164619	0.079017
1975	0.698391	0.292182	0.244446	0.161763	0.077646
1976	0.689151	0.287988	0.240938	0.160225	0.076908
1977	0.680301	0.285192	0.238598	0.157111	0.075413
1978	0.581442	0.243252	0.203510	0.134680	0.064646
1979	0.498735	0.208302	0.174270	0.116163	0.055758
1980	0.425394	0.178245	0.149124	0.098025	0.047052
1981	0.365793	0.153081	0.128072	0.084640	0.040627
1982	0.312216	0.130713	0.109358	0.072145	0.034630
1983	0.268686	0.112539	0.094152	0.061993	0.029758
1984	0.229509	0.095763	0.080118	0.053628	0.025741
1985	0.197037	0.082482	0.069006	0.045549	0.021864
1986	0.142146	0.059415	0.049708	0.033023	0.015851
1987	0.123372	0.051726	0.043276	0.028370	0.013618
1988	0.104598	0.044037	0.036842	0.023719	0.011385
1989	0.087165	0.036348	0.030410	0.020407	0.009795
1990	0.073755	0.030756	0.025732	0.017267	0.008288
1991	0.063027	0.026562	0.022222	0.014243	0.006837
1992	0.054981	0.023067	0.019298	0.012616	0.006056
1993	0.046935	0.019572	0.016374	0.010989	0.005275
1994	0.038889	0.016077	0.013450	0.009362	0.004494
1995	0.033525	0.013980	0.011696	0.007849	0.003768
1996	0.026820	0.011184	0.009356	0.006280	0.003014
1997	0.024138	0.009786	0.008188	0.006164	0.002959
Total	16.710000	6.990000	8.434000	1.286000	0.617280

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Sheet 4
D-4

A DISCOUNTED CASH FLOW TEST
OF THE DETERMINED COST OF WELLHEAD PRODUCTION ON NON-ASSOCIATED GAS

Table 4: Total accounting charges allowable for income tax purposes on the investment outlays pertinent to producing non-associated gas plus attendant condensate and plant liquids.

Year	Total Accounting Charges ¢ (1)	Intangible Successful Well Costs ¢ (2)	Surrendered Leases ¢ (3)	Depreciation ¢ (4)	Depletion (5)
1951	0.085125	0.062496	0.022629		
1952	0.004104	-	0.004104		
1953	0.019722	-	0.019722		
1954	0.002451	-	0.002451		
1955	0.032366	0.031853	0.000513		
1956	0.006751	0.002419	0.004332		
1957	0.030344	0.023789	0.006555		
1958	0.205195	0.182851	0.022344		
1959	0.313837	0.212890	0.100947		
1960	0.551736	0.484647	0.067089		
1961	0.947898	0.552182	0.160626	0.050813	0.184277
1962	0.553446	0.200592	0.099636	0.054731	0.198487
1963	0.402038	0.112694	0.018582	0.058523	0.212239
1964	0.401260	0.091123	0.021831	0.062315	0.225991
1965	0.381199	0.058464	0.018639	0.065728	0.238368
1966	0.304096			0.065728	0.238368
1967	0.304096			0.065728	0.238368
1968	0.295910			0.063959	0.231951
1969	0.281288			0.060798	0.220490
1970	0.271348			0.058650	0.212698
1971	0.263744			0.057006	0.206738
1972	0.257312			0.055616	0.201696
1973	0.252634			0.054605	0.198029
1974	0.247956			0.053594	0.194362
1975	0.244446			0.052835	0.191611
1976	0.240938			0.052077	0.188861
1977	0.238598			0.051571	0.187027
1978	0.203510			0.043987	0.159523
1979	0.174270			0.037667	0.136603
1980	0.149124			0.032232	0.116892
1981	0.128072			0.027682	0.100390
1982	0.109358			0.023637	0.085721
1883	0.094152			0.020350	0.073802
1984	0.080118			0.017317	0.062801
1985	0.069006			0.014915	0.054091
1986	0.049708			0.010744	0.038964
1987	0.043276			0.009354	0.033922
1988	0.036842			0.007963	0.028879
1989	0.030410			0.006573	0.023837
1990	0.025732			0.005562	0.020170
1991	0.022222			0.004803	0.017419
1992	0.019298			0.004171	0.015127
1993	0.016374			0.003539	0.012835
1994	0.013450			0.002907	0.010543
1995	0.011696			0.002528	0.009168
1996	0.009356			0.002022	0.007334
1997	0.008188			0.001770	0.006418
Total	8.434000	2.016000	.570000	1.264000	4.584000

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Sources and Derivations

Table 1, Columns

1 and 2: Pattern of production taken from Item H, Schedule 10.

Column 3: The producer unit gas revenue, after royalty and production taxes have been paid, is set at 13.41 cents per Mcf (14.65 psia). This equals 16.71 cents, the sum of the new gas-well gas allowances determined by the Commission other than royalty and production taxes, less 3.30 cents attributed to liquids. The 13.41 cents is timed per column 1.

Column 4: The liquid revenue has been determined at 3.30 cents for every Mcf of new gas-well gas or about 3.5 cents for lease condensate plus .5 cents for the lease's share of plant liquids, less applicable royalty and production taxes.

Column 5: Column 3 plus column 4.

Column 6: Column 5 translated to percentages.

Column 7: From Table 2, Column 1.

Column 8: These costs chargeable to current production total 6.99 cents per Mcf, a sum made up of 0.15 cents for regulatory expense, 2.70 cents for production operating expense, and 4.14 cents for exploration and development costs (dry holes, etc.).

Column 9: From Table 3, Column 5.

Column 10: Derived by subtracting from Column 5 figures the sum of the figures in Columns 7, 8 and 9.

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Column 11: Derived by applying to the figures in Column 10 the appropriate compounded discount factors for a 12 percent rate, taking 1960 as the base or zero year.

Table 2 — Figures on the total line are the unit costs found allowable in each category. Distribution of these totals by years follows in each case the timing pattern presented in Producer witness Fraser's Exhibit No. 252, Sheet 5.

Table 3, Column 1: From Table 1, Column 5.

Column 2: From Table 1, Column 8.

Column 3: From Table 4, Column 1.

Column 4: Derived by subtracting from the figures of Column 1 the algebraic sum of the figures in Columns 2 and 3.

Column 5: Figures calculated at a 48 percent tax rate.

Table 4, Column 1: Total of Columns 2, 3, 4, and 5. Does not include interest on long term debt.

Column 2: Total is 70 percent of successful well costs, written off at time of expenditure. Timing based on Exhibit No. 252, Sheet 5.

Column 3: Total is 75 percent of the lease acquisition outlay total in Column 2 of Table 2. Distribution is by the dry hole pattern set forth in Fraser's Exhibit No. 252, Sheet 5.

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3

Column 4: Total represents 30 percent of successful well costs plus 100 percent of outlays for other production facilities. Distribution is according to Table 1, Column 6.

Column 5: Depletion calculated at an average effective rate of 26 percent of gross production revenue to the working interest. Gross production revenue is about 20.5 cents — about 16.5 cents per Mcf for gas plus about 4.0 cents for attendant liquids. Working interest equals 86 percent of 20.5 cents.

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APPENDIX E
FLOWING GAS COSTS

Preliminary Questions

In Opinion No. 468 the Commission adopted the cost of old gas-well gas as the basic yardstick for establishing a single ceiling price applicable to all gas other than new gas-well gas or residue gas derived therefrom. In addition, the Commission there further determined that the Staff's composite historical cost of service for old gas-well gas, for the 1960 test year, should be used as the basis for the flowing gas price. (Op. No. 468, pp. 78-79).[1]

[1] The Ameradà group attacks the use of the historical cost-of-service approach in determining flowing gas cost (initial brief, p. 178). However, the Commission settled this question in Op. 468, and no further discussion is required here.

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AGD contends (initial brief, pp. 53-56) that it is improper to cost only the gas well gas and to impute those costs to the gas produced on other types of leases — *i.e.*, combination leases and casinghead gas leases. AGD notes that the costing of gas well gas alone produces higher unit costs than would result from the costing of all flowing gas — *i.e.*, that an upward cost bias is inherent in costing only gas-well gas and excluding gas volumes from combination leases and casinghead gas leases.

The Commission considered and rejected similar arguments in Opinion No. 468 and concluded in dispositive language that the cost of old gas-well gas should appropriately constitute the basic yardstick for establishing a single ceiling price applicable to all gas other than new gas-well gas. (Op. 468, pp. 71 and 78). There are no circumstances in the instant case which justify or require a different treatment. Accordingly, gas-well gas costs alone will be determined here, and the costs so determined will be applied to other types of gas.

In Opinion 468 the Commission held that the ceiling price therein established for flowing gas would be uniformly applicable to all casinghead gas and residue derived therefrom, including that sold or to be sold under contracts dated January 1, 1961, or later. (p. 94) Staff's initial brief herein recommends a departure from this Commission approach in the *Permian* case, and proposes instead that the ceiling price established for new gas should apply uniformly to *all* gas sold under contracts dated January 1, 1961, or later, including new casinghead gas and residue gas derived therefrom. In support of this departure, Staff lists the following considerations: (1) That the gas produced in South Louisiana is uniformly of high quality;

(2) that during the period 1960-1964 there was a relatively stable relationship of about 17.5 percent oil-well gas production to total gas produced in the state of Louisiana; (3) that on the basis of Staff's recommended ceiling prices herein, resulting in a differential of only 0.25 cents between flowing gas and new gas, the proposed Staff departure with respect to casinghead gas would result in an indicated difference of only 0.04 cents per Mcf, which is relatively insignificant;[1] (4) that the proposed departure would be a step in the direction of simplifying the system of area rate ceilings; and (5) that the proposed quality standards would serve to protect consumers in the event that casinghead gas of a quality less than pipeline quality should be introduced into the interstate market in the future.

It is concluded that the considerations listed by Staff, as set forth above, do not have any bearing upon the more basic factors which led the Commission in Opinion 468 to subject *all* casinghead gas to the flowing gas price, regardless of contract date. In dealing with this problem in Opinion 468 the Commission stated:

> "Since oil wells in the Permian Basin are subject to restraints imposed by state regulation upon the amount of oil produced, casinghead gas can be obtained from a given well only for the period each month that oil is under state oil production controls. Correspondingly, since oil is the major product of an oil well, taking the casinghead gas cannot be deferred for any length of time for the buyer's convenience; it must be taken at the time the oil is produced, and

[1] In the instant decision the resulting difference would be more substantial, in view of the 1.25 cents per Mcf spread between the ceiling price of 19.5 cents being fixed herein for new gas and 18.25 cents for flowing gas.

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the amount of gas is related to the oil production. Accordingly casinghead gas is not subject to the exclusive control of the buyer as to time of delivery.

* * * *

"We regard our determination that all gas should be priced on the same basis as old gas-well gas (except for the top ceiling we have established to encourage the search for new gas-well gas which is applicable to such gas whether or not it has been processed) as an important step toward simplified and realistic area price regulation. It is apparent, on this record, that no realistic

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cost of oil-well gas either as casinghead gas or residue gas can be established and that the various apportionments of the joint costs of gas and oil, or gas and liquids, do not yield results which may be accepted as reliable guides. The evidence in this case and the practical administration of area prices dictates that casinghead gas, residue gas derived therefrom, and old gas-well gas, should be similarly priced. Unlike new gas-well gas, there is no basis on this record for differentiation because of the incentive effect, or otherwise." (Op. 468, pp. 70, 71, 76)

The basic considerations set forth in Opinion 468, as quoted above, are equally applicable to the instant case. Accordingly this decision will adhere to the Commission's Opinion 468 treatment of casinghead gas and residue gas derived therefrom, under which *all* such gas will be subject to the ceiling price for flowing gas, regardless of contract date.

The State of Louisiana, in an amicus curiae brief, also objects to the application of the lower flowing gas price to new casinghead gas and to residue gas obtained therefrom, on the ground that this would lead to the creation of con-

servation problems and the premature abandonment of reserves, with consequent detriment to the public interest. It alleges that casinghead gas is frequently produced at the separator at low pressure, requiring gathering, compression and dehydration before it becomes marketable; that accordingly if new casinghead gas and the residue therefrom were restricted to the lower flowing gas price, the price of casinghead gas would frequently be uneconomic, thus resulting in the flaring of such gas or the shutting in of the production.

It is also contended that the application of such lower prices for casinghead gas may cause premature abandonment of oil wells, on the ground that casinghead gas revenue contributes to the total revenue from such wells; that the lower the price for such gas, the sooner the well will become uneconomic and the sooner it must be abandoned.

It is further contended that in any event the producer-sellers of residue gas obtained from new casinghead gas should at least be entitled to charge for residue gas an increment over and above the area field price to compensate them for the cost of gathering, dehydrating and compressing such gas.

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The above arguments advanced by the State of Louisiana were equally applicable to the same issue in the *Permian* case. Nevertheless, they were not found in Opinion 468 to justify any departure from the basic holding with respect to this problem in that case. Accordingly, the Commission treatment of this problem in Opinion 468 is regarded as controlling here, and the State of Louisiana position is rejected.

In Opinion No. 468 the Commission also concluded, upon

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examination of trend data for earlier years, that the 1960 level of costs was fairly representative of costs during the three-year period ending in 1960; that while unit costs were somewhat lower in the earlier years, they had leveled off in 1958 and had not since exceeded that level. The Commission accordingly concluded that the 1960 test year was typical of current and future costs for flowing gas, and was more than fair to the producers as a basis for just and reasonable prices for the prior years when costs were slightly lower.

The considerations which led the Commission to these conclusions are equally applicable and controlling here. The Staff in the instant case used 1960 as the test year in determining the cost of old gas-well gas. It relied upon an analysis of various cost trends presented by AGD witness Roseman as indicating that with respect to the near future "expenditures per unit of production will decline or at worst remain relatively stable." (12:3557-3565; also see testimony by AGD witness Joskow at 17:5744).[1]

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In opinion No. 468 the Commission noted a preliminary question as to whether production costs should be determined on the basis of nationwide costs, or whether Permian area cost evidence alone should be used. The producers there, as in the instant case, argued for the nationwide basis. The Commission concluded that, other than for exploration and development costs, the record pro-

[1] This testimony and the Commission's holding in Op. 468, referred to above, comprise a sufficient answer to the *Sun Oil* argument (initial brief, page 47, *et seq.*) that the use of a 1960 test year in Staff's composited historical cost-of-service was improper.

vided the necessary data to determine production costs incurred in that area; that since the ceiling price to be fixed was an area rate for flowing gas in the Permian Basin, and not a national price, it should be based primarily upon area costs. (Op. 468, p. 80)

In the instant proceeding the Staff and AGD have employed area production costs and that approach is regarded as sound in the light of Opinion No. 468.

A further preliminary question arises as to the use of the questionnaire data from Appendix C, the simplified questionnaire form designed for producers with less than ten million Mcf of annual jurisdictional sales during 1960. In Opinion No. 468 the Commission noted that replies to the Appendix B questionnaire (executed by the major producers) had been received in complete form from 67 respondents in the Permian area; that these respondents included 42 major producers (representing all the major producers in that area except one). On the other hand, although Appendix C questionnaires had been mailed to all of the over 350 small producers in the area, responses were filed by only 105, and of these 69[1] were sufficiently completed to be compiled. Under these circumstances the Commission there held that the responses from the small producers in Appendix C could not be employed, because the percentage coverage was too small and because it did not represent a random sample. (Op. 468, p. 82). The Commission accordingly relied exclusively upon Appendix B data.

[1] Op. 468 (p. 81) refers to a figure of 60, but this was an inadvertence.

In the instant case, Staff's cost of service represents the composite data of both Appendix B and C respondents, constituting an 81-company group. AGD, however, contends that primary reliance should be placed here upon the Appendix B questionnaire data, relating to 47 companies. It notes that although Appendix C questionnaires were mailed to approximately 200 small producers, only 70 responses were received; that of the 70, only 34 of the responses were compositable; that this sample of 34 companies, representing less than four percent of the gas produced by the 81 Appendix B and C respondents, is too small and also suffers from the infirmity of self-selection.

Staff argues, on the other hand, that its purpose was to include all the data which was compositable, whether filed on an Appendix B form or on an Appendix C form; that Staff's 81 company composite cost study represents approximately 85 percent of the natural gas and 87 percent[1] of the liquids produced in South Louisiana as reported in the Louisiana Conservation Commission Report of 1969. (12:1,528). Staff also points out that exclusion of the Appendix C data could not appreciably affect the cost results because their percentage of gas produced is small; that the unit costs of gas in this proceeding would be decreased by only 0.15 cents per Mcf if the Appendix C data were excluded.

It is true that the coverage with respect to Appendix C data in the instant case is similar to that in the *Permian* case, where the Commisison (Op. 468) decided to rely ex-

[1] The figure of 89 percent in Staff's initial brief (p. 161) was an inadvertence.

clusively upon the Appendix-B data. However, the effect upon unit costs of gas resulting from inclusion of the Appendix C data is *de minimis*. Under the circumstances, since (as will be seen) the Staff's historical cost of service presentation is being here adopted, it is more feasible from a practical standpoint to deal with the Staff's 81 company composite, including both the Appendix B and C data, than to recompute the entire historical cost study to reflect exclusion of the Appendix C data. Therefore, the flowing gas cost determination will here be based upon the Staff's 81 company group.

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APPENDIX F

ALLOCATION OF EXPLORATION & DEVELOPMENT COSTS USING FACTORS OF 3.5 FOR LIQUIDS AND 1.0 FOR GAS (INCREMENTAL, U.S., 4% RESERVOIRS, YEAR 1961)

(1)	Volumes: Lease Liquids (Bbl) (2)	Volumes: Gas (Mcf) (3)	Unit Btu: Millions Per (Bbl or Mcf) (4)	Total Btu's (Million Btu's) (5)	Economic Factor (6)	Adjusted Btu's (Million Btu's) (7)	Allocated Expense: Amount $ (8)	Allocated Expense: Unit ¢ Bbl or Mcf (9)	Allocated Return Allowance: Amount $ (10)	Allocated Return Allowance: Unit ¢ Bbl or Mcf (11)	Allocated Expense & Return Allowance: Amount $ (12)	Allocated Expense & Return Allowance: Unit ¢ Bbl or Mcf (13)
Net Working Interest												
Oil Only Leases												
Lease Liquids	330,383,390	-	5.876	1,941,613,438	3.5	6,795,087,033	222,240,007	67.273	38,532,545	11.663	260,772,552	78.936
Raw Gas	-	43,381,046	1.164	50,480,049	1	50,480,049	1,651,148	3.806	286,255	0.660	1,937,403	4.466
Oil Casinghead Gas Leases												
Lease Liquids	711,280,917	-	5.815	4,136,229,176	3.5	14,476,749,616	473,520,023	66.573	82,092,893	11.542	555,612,916	78.114
Raw Gas	-	1,380,092,312	1.280	1,766,405,143	1	1,766,405,143	57,777,217	4.186	10,018,674	0.726	67,795,891	4.912
Gas Only Leases												
Lease Liquids	11,888	-	5.240	271,893	3.5	951,626	31,127	59.989	5,396	10.399	36,523	70.388
Raw Gas	-	805,179,603	1.030	829,591,070	1	829,591,070	27,135,034	3.370	4,704,325	0.584	31,839,359	3.954
Gas-Condensate Lease Separation Leases												
Lease Liquids	52,319,963	-	5.421	283,650,378	3.5	992,777,723	32,472,694	62.068	5,629,700	10.760	38,102,394	72.828
Raw Gas	-	2,723,120,699	1.084	2,950,702,823	1	2,950,702,823	96,514,329	3.544	16,737,419	0.614	113,248,742	4.158
Gas Condensate, No Lease Separation Leases												
Lease Liquids	796,138	-	5.498	4,377,341	3.5	15,320,693	501,224	62.944	86,879	10.913	588,003	73.857
Raw Gas	-	599,597,827	1.150	689,596,502	1	689,596,502	22,548,355	3.761	3,909,318	0.652	26,458,673	4.413
Combination Leases												
Lease Liquids	220,173,510	-	5.790	1,274,905,070	3.5	4,462,167,745	145,952,720	66.290	25,303,414	11.492	171,256,134	77.782
Raw Gas Produced From Oil Wells	-	590,747,903	1.182	698,187,934	1	698,187,934	22,836,879	3.866	3,958,183	0.670	26,795,062	4.536
Raw Gas Produced From Gas Wells	-	134,184,011	1.040	163,469,209	1	163,469,209	5,346,902	3.987	926,478	0.691	6,273,380	4.678
Raw Gas Produced From Gas Condensate Wells	-	961,144,334	1.107	1,037,097,334	1	1,037,097,334	33,922,341	3.530	5,881,021	0.612	39,803,362	4.142
Sub-Total, Raw Gas, Combination Leases	-	1,686,076,448	1.126	1,898,754,477	1	1,898,754,477	62,106,222	3.683	10,767,682	0.639	72,873,904	4.322
Sub-Total, NWI, Lease Liquids	1,315,005,806	-	5.871	7,720,884,698	3.5	26,743,099,436	874,717,995	66.520	151,650,827	11.532	1,026,368,822	78.052
Raw Gas	-	7,237,447,895	1.131	8,185,328,064	1	8,185,328,064	267,733,300	3.699	46,416,172	0.641	314,149,472	4.341
Royalties Received, Lease Liquids	23,121,520	-	5.800	134,098,808	3.5	469,346,378	15,351,810	66.396	2,661,500	11.511	18,013,310	77.907
Raw Gas	-	166,152,415	1.132	188,067,811	1	188,067,811	6,151,496	3.702	1,066,498	0.642	7,217,994	4.344
Total, Lease Liquids	1,338,127,326	-	5.810	7,774,983,506	3.5	27,212,445,814	890,069,805	66.518	154,312,327	11.532	1,044,382,132	78.050
Raw Gas	-	7,403,600,310	1.131	8,373,395,875	1	8,373,395,875	273,884,796	3.699	47,482,670	0.641	321,367,466	4.341
	1,338,127,326	7,403,600,310		16,148,379,470		35,585,841,689	1,163,954,601 1/		201,795,017 1/		1,365,749,618 2/	
Gas Well Gas Computation 3/ @ 12% Return		5,223,226,634					185,467,936	3.551	32,134,080	0.615	217,602,016	4.166

1/ Total Distributed on Basis of Adjusted Btu's in Column (7).
2/ Total Expense Data Obtained from Exhibit No. 29, Schedule No. 6.
3/ Return Allowance Data Obtained from Exhibit No. 29, Schedule No. 5, Line 29 times 12%.
4/ Based upon the Costs and Volumes Related to Gas Produced from Gas Wells.

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RATE SCHEDULE QUALITY STATEMENT -- SOUTHERN LOUISIANA AREA

1. PRODUCER NAME AND RATE SCHEDULE NO.

2. PURCHASER

3. DATE(S) OF CONTRACT AND/OR AMENDMENT(S) ADDING ACREAGE

	Contract	Amendment(s)	Date
A.	☐	☐	On or before 1/31/61
B.	☐	☐	1/1/61 - 1/31/68
C.	☐	☐	On or after 1/1/69

4. TYPE(S) OF GAS *

A. ☐ Gas-well Gas or Residue Derived Therefrom

B. ☐ Casinghead Gas or Residue Derived Therefrom

5. TAXING JURISDICTION *

A. ☐ State B. ☐ Federal C. ☐ Disputed

6. GAS QUALITY, DELIVERY CONDITIONS AND REDUCTIONS FOR SUB-STANDARD GAS. (Note: This Section to be completed for Contracts and/or Amendments dated on or after 1/1/69.)

A. IMPURITIES:

	Content	Amount of Reduction
a. Hydrogen Sulphide (gr/Mcf)		¢/Mcf
b. Total Sulphur (gr/Mcf)		¢/Mcf
c. Carbon Dioxide (gr/Mcf)		¢/Mcf
d. Water (lb/Mcf)		¢/Mcf
e. Other (Kind and Amount)		¢/Mcf
f. Total Reduction for Impurities		¢/Mcf

B. DELIVERY PRESSURE:

a. Actual Delivery Pressure (psig)

b. Pressure Available at Point of Delivery

c. Reduction for Sub-Standard Pressure ¢/Mcf

C. DELIVERY POINT:

a. Actual Point at which Gas is first Delivered to Purchaser *

☐ Wellhead; ☐ Central Point; ☐ Tailgate; ☐ Offshore Platforms; ☐ Other.

b. Point of Re-delivery to Measurement for Payment. (If Applicable)

☐ Wellhead; ☐ Central Point; ☐ Tailgate; ☐ Offshore Platforms; ☐ Other.

c. Reduction for Wellhead Delivery ¢/Mcf

D. TOTAL REDUCTION FOR QUALITY AND DELIVERY DEFICIENCIES ¢/Mcf

7. HEAT CONTENT (Record Average Btu Content of sales volume used for billing purposes.).

A. Average Btu Content Btu/cu. ft.

B. Btu Adjustment - plus or (minus) ¢/Mcf

8. APPLICABLE AREA RATES FOR SALE **

A. Applicable Area Base Rate(s)	¢/Mcf	¢/Mcf	¢/Mcf
B. Applicable Area Rate(s) Applicable Area Base Rate less or Plus or Minus 1.0¢	¢/Mcf	¢/Mcf	¢/Mcf
C. Contract Rate(s)	¢/Mcf	¢/Mcf	¢/Mcf
D. Rate Where Established (Lower of B or C)	¢/Mcf	¢/Mcf	¢/Mcf
E. Basis for Area Base Rate			
F. Percentage of Gas at each Rate	%	%	%

9. Signature of Seller, Agent and/or Operator

Name:

Title:

Date:

10. Signature of Purchaser

Name:

Title:

Date:

NOTE: The terms used herein are those used in the Opinion of the Federal Power Commission in Southern Louisiana Area Rate Proceedings, AR61-2.

* Check appropriate boxes as appropriate.

** If it is claimed the area base rate is applicable by virtue of variations in the dates of contracts and or amendments (Section 3, Item B, Types of Tax Jurisdiction (Section 5), enter each base rate determined under a separate vertical column and indicate on Line B (E) the basis for each rate by reference to Sections 3,4 and 5 as appropriate. For example, if a portion of the gas sold under a contract dated in 1962 is gas-well gas and a portion casinghead gas, enter "4(A)"(Section 4, Item A) under the rates listed for gas-well gas and "4.B." Section 4, Item B) under the rates listed for casinghead gas.

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Docket No. AR61-2, et al. - 1 - APPENDIX H

(Revised 2/1/68)

APPLICATION FOR SMALL PRODUCER
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY.
(See § 157.40 (b) (4))

NOTE: Independent Producers of natural gas whose total jurisdictional sales on a nationwide basis for the preceding calendar year, combined with those of "affiliated producers," were not in excess of 10,000,000 Mcf may file the information called for in this form for a Small Producer Certificate to sell gas (in four copies). Include volume of gas paid for but not taken under prepayment clauses or otherwise, and volumes of gas sold under other independent producer rate schedules in the proportion that the independent producer seeking to come within Section 157.40 has an interest in such sales. Do not include sales made pursuant to percentage sales contracts. If insufficient space is given for a complete answer, continue the answer on the reverse side or on a separate sheet, noting the relevant number.

1. NAME OF APPLICANT

2. STATE OF ORGANIZATION

3. LOCATION OF PRINCIPAL PLACE OF BUSINESS

4. TYPE OF ORGANIZATION (Corporation, partnership, joint venture, etc.)

5. PERSON RESPONSIBLE FOR APPLICATION:
NAME AND TITLE

MAILING ADDRESS

6. TOTAL JURISDICTIONAL SALES VOLUMES AT _____ PSIA FOR CALENDAR YEAR PRECEDING APPLICATION
(If more than one applicant is to be covered by this certificate, give the total jurisdictional sales volumes of each applicant separately.)

7. LIST ALL CERTIFICATES PRESENTLY HELD BY DOCKET NUMBER AND LIST ALL CONTRACTS ON FILE WITH THE COMMISSION AS RATE SCHEDULES BY RATE SCHEDULE NAME AND NUMBER. INCLUDE IN SUCH LISTING APPLICANTS' INTERESTS IN GAS SALES COVERED BY OTHER PRODUCERS' CERTIFICATES AND RATE SCHEDULES. LIST ALL INTEREST OWNERS AND THE AMOUNT OF THEIR INTEREST FOR EACH SALE TO BE COVERED BY THIS CERTIFICATE. DESIGNATE ANY SALES NOT TO BE COVERED BY THIS CERTIFICATE. (See reverse side for reporting.)

8. LIST ALL OWNERS OF MORE THAN 10 PERCENT INTEREST IN APPLICANT: (A) INDIVIDUAL NAME; (B) PERCENT OF OWNERSHIP

9. LIST ALL INTEREST OWNED BY THE INDIVIDUALLY NAMED OWNERS IN OTHER NATURAL GAS COMPANIES: (A) INDIVIDUAL NAME; (B) COMPANY NAME; (C) PERCENT OF APPLICANT OWNERSHIP.

10. LIST FOR EACH OWNER THE POSITIONS HELD BY THESE INDIVIDUAL OWNERS IN APPLICANT COMPANY OR ANY OTHER NATURAL GAS COMPANY

11. IS APPLICANT OR ANY INDIVIDUAL OWNER LISTED, AFFILIATED WITH ANY PURCHASER OF JURISDICTIONAL GAS FROM APPLICANT? (If so list name of buyer and seller for each sale and nature of affiliation.)

Signature | Title | Date

4185222

Sales Under Rate Schedule of Applicant

Applicant	Docket No.	Rate Schedule No.	Interest Ownership Under Rate Schedule	
			Name	% Interest

Applicants Sales Under Rate Schedule of Others

Other Seller	Docket No.	Rate Schedule No.	Applicants Interest in Rate Schedule

NOTE: Place an Asterisk (*) after each sale above that is not to be covered by the Small Producer Certificate applied for. Place a double asterisk (**) after each co-owners name whose interest is not to be covered by the Small Producer Certificate applied for.

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(308,254)

308,254

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

AREA RATE PROCEEDING (Southern Louisiana Area) AMERADA PETROLEUM CORPORATION, *et al.*	*Docket Nos.* AR61-2 RI60-18, *et al.*

ERRATA NOTICE
(October 9, 1968)

OPINION NO. 546
(Issued September 25, 1968)

Page 53, Second paragraph, line 3: Change "complied" to "compiled".
Page 88, First full paragraph, line 6: Change "buyers'" to "buyer s'".
Page 95, First paragraph, line 7: Change "relef" to "relief".
Page 117, First full paragraph, line 9: Insert hyphen after "by".
Page 136, Third full paragraph, line 4: Change "*Permain*" to "*Permian*".
Appendix A, page B-8, Second full paragraph, line 11: Insert comma after "rate".
Appendix B, page B-13, Second full paragraph, line 11: Change "his" to "this".
Appendix B, page B-14, first paragraph, line 16: Change "symetrically" to "symmetrically".

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Appendix B, page B-19, Second full paragraph, line 5: Change "conjuction" to "conjunction".
Appendix G, Item 3B: Change date from "12/31/68" to "9/30/68".
Appendix G, Item 3C: Change date from "1/1/69" to "10/1/68".
Appendix G, Item 6, line 2: Change date from "1/1/69" to "10/1/68".

Gordon M. Grant,
Secretary.

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UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

AREA RATE PROCEEDING (Southern Louisiana Area) AMERADA PETROLEUM CORPORATION, *et al.*	*Docket Nos.* AR61-2 RI60-18, *et al.*

ERRATA NOTICE
(October 31, 1968)

OPINION NO. 546
(Issued September 25, 1968)

Page 149, Ordering paragraph (E)(1), line 7: change "filing of" to "first delivery under".
Appendix A, Page A-3, delete "Proctor, Sterrett B."

(308,258)

Appendix A, Page A-4, delete "Wolfe Oil and Gas Company".

Appendix A, Page A-5, change following to read:

Austral Oil Company, Inc. (Oper.) *et al.*	G-13842, G-16891, G-17797, G-19830, RI61-179, RI62-93, RI63-146
Austral Oil Company, Inc. (Oper.), Agent for Oil Participations, Inc.	G-13177, G-18270, G-19913, RI61-137, RI61-175, RI62-94, RI62-360, RI62-484, RI63-154, RI63-155, RI64-223

Insert:

Austral Oil Company, Inc. (Oper.) Agent for Oil Participantions, Inc. and Pan American Petroleum Corporation	G-19642, RI63-144, G-16515, RI62-99
Continental Oil Company	G-16701, G-17936, RI60-334, RI61-470
Continental Oil Company (Operator), *et al.*	RI63-168, RI60-165

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Docket No. AR 61-2, *et al.*

Appendix A, Page A-6, change following to read:

General American Oil Company of Texas	G-19476, G-19875, G-19924, RI61-173,

Insert:

General American Oil Company of Texas (Oper.), *et al.*	RI61-321, RI62-133, RI62-302 RI62-234, RI63-127, RI63-161, RI63-162
Kerr-McGee Corporation	G-16082, G-19872, RI60-452, RI61-514, RI62-378

Insert:

Kerr-McGee Corporation (Oper.), *et al.*	G-16697, G-17155, G-17882, G-19914, RI61-191, RI62-62, RI63-158

Appendix A, Page A-7, change following to read:

Pan American Petroleum Corporation, (Oper.), *et al.*	G-19641, G-19765, RI63-138
Phillips Petroleum Company	G-11991, G-14260, G-16712, G-16083, G-17267, G-17740, G-17920, G-20013
Phillips Petroleum Company, (Oper.), *et al.*	G-16600, G-18414
Placid Oil Company, *et al.*	G-13180, RI62-257

Appendix A, Page 8, change following to read:

Southwest Gas Production Company, Inc., *et al.*	G-18100
Tesoro Petroleum Corporation, *et al.*	RI62-358
Tribune Oil Corporation, *et al.*	G-6279, G-13032
Union Oil Company of California	G-13438, G-16602, G-19006, G-19609, RI60-450, RI61-80, RI62-43, RI63-117

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Docket No. AR 64-2, *et al.*

U. S. Oil of Louisiana, Inc. (Oper.), *et al.*	G-19874

Delete:

Vincent & Welch, Inc. (Oper.), *et al.*	G-19261

Gordon M. Grant,
Secretary

APPENDIX E

Federal Power Commission
Opinion No. 546-A
Southern Louisiana Area Rate Proceeding
Dockets AR61-2, et al.
(March 20, 1969)

(309,072)

309,072

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

OPINION NO. 546-A

Area Rate Proceeding (Southern Louisiana Area)	*Docket Nos.* AR61-2
Amerada Petroleum Corporation, *et al.*	RI60-18; *et al.*

OPINION AND ORDER ON REHEARING MODIFYING IN PART AND CONFIRMING IN PART PRIOR OPINION AND ORDER AND DENYING MOTIONS FOR STAY

Issued: March 20, 1969

309,073

OPINION NO. 546-A
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UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

AREA RATES; GAS SUPPLY; NATURAL GAS ACT—Sections 4(e), 5(a); OFFSHORE TRANSPORTATION; PRICE STRUCTURE; QUALITY DIFFERENTIALS; DELIVERY PRESSURE; RATES—Independent Producer; RATE DESIGN; REFUNDS; STAY; SPECIAL EXEMPTIONS

Before Commissioners: Lee C. White, Chairman; L. J. O'Connor, Jr., Carl E. Bagge, and John A. Carver, Jr.

	Docket Nos.
Area Rate Proceeding (Southern Louisiana Area)	AR61-2
Amerada Petroleum Corporation, *et al.*	RI60-18, *et al.*

OPINION NO. 546-A

OPINION AND ORDER ON REHEARING MODIFYING IN PART AND CONFIRMING IN PART PRIOR OPINION AND ORDER AND DENYING MOTIONS FOR STAY

(Issued March 20, 1969)

WHITE, Chairman;

On September 25, 1968, the Commission issued its Opinion No. 546 in the above-entitled proceeding determining and establishing just and reasonable rates for natural gas producers in the Southern Louisiana area. Applications for rehearing, clarification and stay of the order have been filed by various parties.[1] Most of the rehearing applications, filed by producers, urge that the rates established in the

[1] Appendix A lists the filings made with the Commission.

decision have been set at too low a level. The New York Commission, the Municipal Distributor Group and certain distributor interveners, on the other hand, argue that the rates are excessive and should be reduced. The application for rehearing filed by the Hunt group of respondents includes a motion to reopen the proceeding for the receipt of evidence. Two petitions to intervene were granted by order issued November 29, 1968. On our review of the many filings we find that the applications for rehearing consist in large part of the repetition of contentions previously expressed in

the proceeding and which were fully considered by us in the course of the deliberations leading up to Opinion No. 546. Many of these contentions are specifically answered in the Opinion. Nevertheless, we have considered all claims and arguments made in the applications and are persuaded that certain modifications should be made in the Opinion and accompanying order. In addition we wish to clarify certain findings in the Opinion with respect to which questions have been raised and to respond to certain contentions not previously advanced.

Gas Supply and Second Round Proceeding for Federal Domain

Many of the petitions for rehearing filed by the producers herein,[2] and the motion for further oral argument filed by the Pipeline Group on November 22, 1968, devote primary attention to the basic question of the adequacy of present gas supplies to meet the increasing demands for

[2] The Amerada Group, The Hunt Group, Sun Oil Co., Shell Oil Co., Texaco Inc., Samedan Oil Co., and Bradco Properties Inc., *et al.*

natural gas and the adequacy of the rates established in Opinion 546 to elicit the future exploration, development and dedication necessary to meet this demand. No probative showing, based on the record before us, has been made in any such pleadings indicating that the prices we have established will be inadequate to bring forth the optimum degree of effort by the industry. However, the pleadings do lead us to the conclusion that the vital importance of future additional gas supply from the offshore areas in Southern Louisiana warrants the immediate commencement of the further proceeding we had contemplated in our original Opinion herein looking towards a possible revision of the area price ceilings for such gas.

This proceeding is being instituted by separate order issued concurrently herewith. Moreover, to insure that the institution of this new proceeding will not inadvertently have the effect of discouraging necessary new contracting during its pendency, we have determined that it would be appropriate to modify the moratorium adopted in Opinion No. 546 to permit producers certificated to make sales of gas in the

offshore areas[3] under contracts entitled to the third vintage price (18.5¢ as adjusted for quality), to file for contractually authorized increases up to the price which would be authorized for such sale under Opinion No. 546 had it been subject to the Louisiana State taxing jurisdiction. It is contemplated that rates pursuant to such filings would

[3] As used herein, offshore areas include Zones 2, 3 and 4 as described in the Interim Agreement between the United States and the State of Louisiana, dated October 12, 1956, as amended, exclusive of those areas awarded to the State of Louisiana by Supplemental Decree of the Supreme Court, entered December 13, 1965, 382 U.S. 288.

be permitted to become effective, subject to suspension and possible refund, depending upon the outcome of the new proceeding. Moreover, if the Commission established a lower rate for fourth vintage contracts than the third-vintage price, that lower area rate will not be applied to deliveries thereafter made under third-vintage contracts.

We believe that the new proceedings should be separate and apart from this proceeding, the conclusion of which is overdue. Thus, while we are incorporating by reference the entire record in Docket No. AR61-2, *et al*, into the new proceeding, we will deny the request that the two proceedings be consolidated.

There have been suggestions in some of the pleadings that a further inquiry into the adequacy of our rates to induce the required supply should also encompass the on-shore portions of the Southern Louisiana area or even earlier vintages of gas. The contention as to earlier vintages is essentially a reiteration of the arguments against a multi-price area rate system which we have fully discussed in Opinion No. 546. It is sufficient here to state that nothing new has been advanced since Opinion No. 546 was issued to change our view that, assuming the rate set for future dedications is adequate, the industry will have no difficulty in devoting the funds required to do the task.

The reasons for instituting a new proceeding do not apply to the onshore prices at this time. All presently available evidence indicates that it is (from) the offshore areas — the very ones concerning which the record in this proceeding was least adequate as to costs, committed and uncommitted reserves, and production patterns — that

the industry must look to for most of the additional gas to be dedicated from Southern Louisiana. Thus the Form 15 data for Southern Louisiana shows that most of the impressive growth of reserves dedicated to the interstate pipeline companies in this area during the five-year period 1963-1967 related to offshore gas supplies. The dedicated reserves in the area as a whole rose from 66,530 million Mcf, at the end of 1963, to 72,850 million Mcf at the end of 1967, despite production during this period of over 16,000 million Mcf. During the period, however, offshore reserves dedicated increased from 18,500 million Mcf to 27,230 million Mcf, while Southern Louisiana onshore dedicated reserves were actually declining (from 43,540 million Mcf to 39,230 million Mcf). Pipeline takes from onshore reserves increased by 590 million Mcf, and from offshore reserves by 650 million Mcf, during this period. These figures omit warranty contracts (which involve substantial amounts of offshore gas) where the dedicated reserves rose by 1,900 million Mcf, and production went from zero to 210 million Mcf.[4] In short, all indications at this time confirm that any new proceeding to be instituted should focus on securing the hard facts on this vital offshore area from which so much of the additional gas supply for the eastern United States can be expected to come.

Several producers have objected to our imposition of an indefinite moratorium on the filing of rate increases in Opinion No. 546. While the bases for our action need not be repeated, it seems appropriate to reiterate that the imposition of an indefinite moratorium — like the morator-

[4] During the period, Southern Louisiana as a whole accounted for 20,250 million Mcf of gross gas supply accretions dedicated to pipeline companies; Permian Basin for 14,620 million Mcf; Hugoton-Anadarko for 5,290 million Mcf; the Texas Gulf Coast for 4,970 million Mcf; the other Southwest area for 4,240 million Mcf; and all other areas for 3,130 million Mcf.

ium for a fixed period does not mean either that the rates prescribed are permanent or that the moratorium will not be lifted or modified to permit increased rate filings whenever adequate reason for permitting such filings is shown. Nevertheless, with respect to the 20.0 cent ceiling price we have established for third vintage onshore gas,[5] we have concluded that the public interest would

be served by fixing an outer limit on the period within which contractually authorized rate increases cannot be filed. This ceiling governs the price at which future dedications of gas in the on-shore area can be made and relates to the future period in which cost and other relevant changes are more likely to occur. We believe that in such circumstances the public interest will benefit from greater certainty as to the maximum duration of the moratorium. Accordingly, we shall modify our decision herein to prescribe that the moratorium on rate filings above the just and reasonable ceiling for third vintages on-shore gas in the Southern Louisiana area will expire on January 1, 1974.

Effective Date of the Opinion

Ordering Paragraph (J) of Opinion No. 546 fixes the effective date of the Order, and of the prescribed rates, as September 25, 1968, the date on which the Opinion issued. A number of producers, including the Amerada Group, the California Co. and Atlantic Richfield Co., have contended that a mid-month effective date is unduly burdensome for the reason that, since all industry accounting systems are conducted on a monthly basis, a change in rates in the

[5] The offshore situation is discussed *supra*, at p. 2-3 and the Order Instituting Investigation and Proposed Rulemaking, Docket No. AR69-1.

middle of an accounting period would create substantial bookkeeping problems in fractionating monthly statements. Atlantic Richfield Company further notes that since State law requires royalty owners to be paid on actual volumes and revenues, it would be necessary as matters now stand to make a day-by-day examination of the volumes and revenues under each rate schedule.

We are persuaded by the arguments that the effective date of the Opinion should be moved to October 1, 1968 and our order herein so provides. In thus delaying the effective date of certain of the rate reductions ordered by the Opinion, we are aware that the overall impact of our determination is thereby reduced in a substantial (although uncalculated) amount.

Notice of Effective Date

A number of the producers[6] allege that, since the substance of our decision was incorporated into a rule of general appli-

cability, we could not, in the absence of any finding of good cause published with the rule, make our decision effective as of the date we issued our Opinion. Instead, they contend Section 4(c) of the Administrative Procedure Act requires that the effective date be not less than 30 days thereafter. The argument is without merit.

Pursuant to the provisions of Section 2(c) of the Administrative Procedure Act, any "approval or presumption for the future of rates . . . prices . . . services . . . or practices

[6] Including the Amerada Group, Samedan Oil Co., Forest Oil Co., Bradco Properties, Inc., *et al.*, The California Co., Texas Gas Exploration Corp. and The Superior Oil Co.

bearing upon any of the foregoing" involves rulemaking. This does not mean, however, that the express provisions of Section 4(e) of the Natural Gas Act providing for retrospective application of rate determinations in suspended rate increase proceedings to the date the higher rate was placed in effect was intended to be affected by the provisions of Section 4(e) of the Administrative Procedure Act. Nor was the Commission's power under Section 5(a) of the Natural Gas Act to fix rates by order "to be thereafter observed and in force" thereby modified to impose an additional thirty-day period of grace to charge rates found not to have been just and reasonable.

Thus, the rates fixed in the *Permian* decision in Docket No. AR61-1 were with the approval of the courts made effective as of September 1, 1965, less than 30 days from the date of issuance of our decision. The same is true here, and the fact that the decision, after full compliance with the notice provisions of Section 4 of the Administrative Procedure Act, has been codified into a general rule prospectively applicable as well to producers not named as parties to the proceedings under Sections 4 and 5 of the Natural Gas Act, does not afford those who participated with an additional period to charge rates above those found to be just and reasonable.

Classification of Gas on Basis of Contract Date

The Amerada Group, Atlantic Richfield Co., Signal Oil and Gas Co. have again argued that gas sales should not be vintaged by contract date but, instead, on the basis of the date the gas was or is first committed to interstate commerce. In Opinion No. 468-A, the use of the contract date was justified on the basis that "that date is precise, definite and certain, whereas the date of commitment of gas to interstate commerce is less easy of ascertainment." The same fac-

(309,080)

tors are persuasive here for holding to the date of the contract. Although the Amerada Group of producers contend that the date of initial delivery is just as certain, and can easily be

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ascertained since the Commission's regulations require that a producer file such information upon commencing deliveries, our investigation discloses that not all producers filed this information with the Commission.[7] Moreover, the contract date is more closely related to the time at which the economic commitment for the search for new supplies of gas is made than is the date of initial delivery. Since exploration and development expenditures occur in advance of the contract date, an argument can be made that, in theory, the division date should be even before the contract date, *e.g.*, the initial lease acquisition date. However, the contract date is the earliest date which is definite and known whereby the producer agrees to commit his gas supply to interstate commerce.

We note that since the applications for rehearing were filed, the Tenth Circuit has held that Opinion No. 468 failed to specify whether the governing contract date in all cases should be the date shown on the face of the contract or whether it could be some later date, alleged by a party to the contract to be the actual date of execution.[8] In Opinion No. 546 we have specified that "*the date on the face of* the gas-well gas sales contract should be determinative of

[7] The producers' questionnaire underlying the Southern Louisiana settlement proposal contains initial delivery information for 505 contracts; however there are many contracts for which this information is not available.

[8] *Mobil Oil Corp.* v. *F.P.C.*, CA10, No. 8829, issued January 2, 1969.

whether the sale is to be considered as new or flowing gas."[9] Ordering paragraph (A) of Opinion No. 546, amending Part 154 of the Regulations, vintages the gas sales on the basis of contract date. By contract date we mean the contract date as stated by the gas sales contract. Wherever such a date appears in the contract, it shall be used to determine which of the base ceiling rates is applicable to the particular sale. With our statement in the Opinion, as additionally clarified herein, the problem presented in the *Mobil* case should not arise with regard to any of the contracts affected by the Southern Louisiana decision.

The argument that the date of the contract test penalizes those producers who have helped to effectuate our recent policy announcement with regard to new pipeline contraction proposed for offshore Louisiana, set out in Order No. 363,[10] is, we believe, taken care of in the next section of this order specifically dealing with this problem. We do not believe any overall change in our decision on this issue is warranted.

Special Relief

A number of the applications[11] make the argument that the use of an October 1, 1968 contract date as the earliest date for third vintage gas has "entrapped" certain producers who, as a result of Commission orders issued in

[9] Mimeo. p. 21 (emphasis added).

[10] Policy with Respect to the Issuance of Certificates of Public Convenience and Necessity to Pipeline Companies in the Southern Louisiana Off-Shore Area, Docket No. R-341, Order No. 363, 39 FPC ....., issued June 4, 1968.

[11] The Amerada Group, Atlantic Richfield Co., the Pipeline Group; Sea Robin Pipeline Co. and Tennessee Gas Pipeline Co.

(309,082)

May and June 1968, entered into contracts before September 1, 1968, to supply planned offshore pipeline extensions. Applicants contend that the Commission by its orders encouraged the execution of the producer contracts underlying the pipeline applications prior to September 1, 1968, and then gave a higher price for contracts dated October 1, 1968, and thereafter.

The issue arises from Commission orders of May 3, 1968, in *Michigan Wisconsin Pipeline Company*, Docket No. CP68-36 and *Transcontinental Gas Pipe Line Corporation*, Docket No. CP68-177, and from the Commission's Order No. 363, issued on June 4, 1968. The May 3 orders required Transcontinental and Michigan-Wisconsin

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to file applications for future offshore Southern Louisiana transmission facilities on or before September 1st of the year immediately preceding the proposed installation of such facilities. Order No. 363 formalized this requirement as a policy applicable to all pipelines operating in offshore Southern Louisiana. As a result of the foregoing, a number of applications were filed between August 30, 1968 and September 3, 1968.[12] The pipeline applications were accompanied by producer applications.[13]

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[12] Sea Robin Pipeline Company, Docket No. CP69-48; Southern Natural Gas Company, Docket Nos. CP69-45, CP69-46, CP69-47; Texas Eastern Transmission Corporation, Docket No. CP69-52; Tennessee Gas Pipeline Company, Docket Nos. CP69-50 and CP69-53; Columbia Offshore Pipeline Company and Columbia Gulf Transmission Company, Docket Nos. CP68-231, CP69-120, CP69-121; Transcontinental Gas Pipe Line Corporation, Docket No. CP69-51; Michigan-Wisconsin Pipe Line Company, Docket Nos. CP69-44; CP69-90.

[13] Some of the pipeline applications (notably Southern Natural and Texas Eastern) relied to a considerable extent on future commitments of gas.

It appears that the producer contracts supporting the pipeline applications are dated from January 15, 1968 to August 27, 1968. The applications for rehearing generally request use of either May 3, 1968, or June 4, 1968, as the contract date eligible for the third vintage rate. It further appears that no contracts supporting the offshore applications are dated between May 3 and June 4 so that, if relief is limited to such contracts, selection of either date would have the same effect. The applications for rehearing variously request that the cut off date for third vintage gas be changed to May 3 or June 4:

(1) for all contracts executed after that date;

(2) for all offshore contracts executed after that date; or

(3) for all contracts specifically connected with applications for new offshore facilities.

A cut-off date of May or June 1968, for all contracts is entirely unjustified and would render unrealistic the incentive feature of the third vintage prices. The extension of the higher price to all offshore contracts dated after June 4, 1968, presents this same problem and, in addition, would raise the issue of the Commission establishing an unsupported preference between offshore and onshore rates.

Limitation of the third vintage price to those contracts related to the applications for new offshore facilities filed pursuant to Order No. 363 would likewise constitute a preference between persons and a difference in rates. The question is whether such an allowance would be "undue" or "unreasonable" in terms of Section 4 of the Natural

(309,084)

gas Act or "unduly discriminatory" under Section 5. In our opinion it would not.

Appendix B lists the producer contracts bearing dates between May 3, 1968 and October 1, 1968 underlying the pending pipeline applications filed pursuant to Order No. 363. It may be noted that these contracts, of which there are twelve, are all dated during the month of August 1968. Based on the information provided in the related pipeline applications and our own knowledge of the effect produced by our issuance of the order on the pipelines considering new construction offshore Southern Louisiana, namely an acceleration in all areas related to the filing of the applications and supporting materials, we believe that we are warranted in concluding that these contracts would not have been executed by the producers at the time at which they were but for the pressures created by our order. In view of the close proximity in time between the contract dates and the October 1, 1968 commencement date for our third vintage rate, it appears that in normal course the contracts would have been finalized on or after October 1, 1968. Accordingly, those producers having contracts dated between June 4, 1968 and October 1, 1968 for sales of gas in connection with the applications for offshore facilities set forth in Appendix B hereto will be granted special relief so as to be treated in the same manner as those producers having contracts dated on or after October 1, 1968. They will be subject to the same area rate and to all provisions of Opinion No. 546 relating to contracts dated after October 1, 1968.

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This action does not extend comparable relief to those producers who executed contracts which are dated prior to

June 4, 1968, in connection with Transcontinental's application in Docket No. CP69-51 and with Columbia Offshore Pipeline Company in Docket No. CP68-231, since the considerations detailed above are not applicable to these cases.

Signal Oil and Gas Company (Operator), *et al.* (Signal) filed an application on November 8, 1967, for a certificate in Docket No. CI68-639 covering a sale to Transcontinental of gas to be produced offshore Southern Louisiana. The contract covering the sale is dated October 3, 1967. Temporary authorization was granted by order dated May 3, 1968. However, deliveries by Signal had not commenced at the time the applications for rehearing were filed.[1] In its application Signal argues that it should be allowed the third vintage ceiling since deliveries were not initiated prior to October 1, 1968.

The argument is identical with those previously considered and rejected for a cut-off date based on the date of initial delivery rather than contract date. No special equities are alleged in the application which would warrant exceptional treatment. Accordingly, Signal's application will be denied.

New Gas Well Gas Developed on Committed Acreage

The Amerada Group of producers, the Hunt Group, Shell Oil Co. and Sun Oil Co. contend that we have abused our discretion by refusing to decide at this time whether gas produced from newly discovered reservoirs on previously committed acreage should receive the vintage price in effect at the time the reservoir was discovered or the vintage price in effect at the time the contract was made. In our decision we deferred resolution of this issue to the proceedings in Docket No. AR64-1, where a record on the subject

[1] Signal has since informed the Commission that deliveries under the contract commenced on December 26, 1968.

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has been compiled. Any change in policy, we have stated, will be applied prospectively in both the

Permian Basin area and the Southern Louisiana area. The producers ask that we now reopen the record here to receive the evidence present in AR61-1. We believe that the final determination should be left to that proceeding, where an Examiner's decision has already been issued, and that we should not here attempt to resolve the question. Although the issue as framed in *Permian* was limited to "additional discoveries of gas-well gas from deeper reservoirs," the applications for rehearing are addressed to the merit of permitting the new gas price to be charged for production from all new reserves developed on previously committed acreage, irrespective of whether such reserves are developed at deeper producing horizons or are the same or shallower depths as the existing production. This additional question further complicates the determination and reinforces our decision that the issue should properly be left for resolution in the *Hugoton-Anadarko Area proceeding*.

Sun Oil Company has asked for a stay of the rate reductions ordered in Opinion No. 546 in the case of "new production" under contracts executed prior to January 1, 1961, so that if we were to hold that some or all of such production is entitled to the new gas price, it will not be precluded from collecting such price in the interim. Without now attempting to pass upon the merits of the question generally, or whether any decision to give "new production" from previously dedicated acreage the new gas price would apply to flowing gas, we think it clear that there is no basis for concluding that any delay in applying any possible new policy to flowing gas will significantly affect gas supply.

On the other hand, we agree that the public interest in resolving the issue as soon as possible warrants special action. Accordingly, we have severed this issue from the others in the pending *Hugoton-Anadarko* case so that its resolution need not await the other issues in that and its companion proceeding.[15]

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Casinghead Gas Price.

The Amerada Group of producers, the Hunt Group, Shell Oil Co. and Sun Oil Co. assert error in our applicaiton of the pre-1961 area ceiling rate to second and third vintage casinghead gas. While it is true that contracts for associated gas produced in Southern Louisiana in the past have generally carried prices on a par with gas-well gas, we can percieve no justification for continuing to allow the more recent vintages of this gas to command a price which is based in part on an additional allowance which includes an incentive for increased exploration and development and which is predicated on the industry's directional exploration capability. Moreover, while we have consciously refrained from attempting to define the cost of casinghead gas, we are well aware that its indicated cost is substantially below that of gas-well gas. We find no merit to the claims that we should allow the higher rates applicable to new gas-well gas to the more recent vintages of casinghead gas.

Platform Delivery

The Amerada Group, The California Co. and Texaco Inc. producers request clarification of certain statements

[15] *Area Rate Proceeding, et al.* (Hugoton-Anadarko Area), Docket No. AR64-1, *et al.*, Order Severing Issue For Early Decision, issued February 4, 1969.

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at page 89 of the Opinion, and in Ordering Paragraph (A)(d)(viii), to the effect that when delivery is made to a pipeline purchaser at an offshore platform, the line to the platform having been built by the pipeline, the gas is to be considered as having been brought to a central point and that there will be no deduction for "delivery point". This was the intent of our Opinion and, to the extent that clarification thereof is needed, it is so provided. We are aware that several wells are commonly drilled from a single platform and the gas from each of these wells is centrally collected and delivered to the pipeline buyer at the platform. In such a circumstance, no deduction is to be made for delivery point from the otherwise applicable area price.

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Federal Domain Gas Delivered Onshore

Some gas produced within the Federal domain offshore is transported to shore by the producers, or at their expense, and there sold. As stated in Opinion No. 546 we are unable at this time to determine whether, or to what extent, an increment over and above the rates applicable to gas produced in the Federal domain is justified in such cases. Such determination will be made upon application in individual cases for special relief as provided in Opinion No. 546. Pending such determination the Amerada Group and The California Company ask that those who produce gas in the Federal domain but deliver it, or pay for delivering it, onshore should be allowed to collect the onshore rates which are 1.5 cents per Mcf higher than the rates applicable in the Federal domain.[16] They urge that such producers have incurred costs over and above the costs of those who

[16] Texaco Inc., a member of the Amerada Group, also raised the same issue in its supplemental application for rehearing.

produce and sell gas within the Federal domain. No such costs were included in the unit cost computations. The producers contend that any such costs of transportation should be added to the cost computations previously found applicable in the case of Federal domain gas.

One factor to be considered is that the costs incurred by a producer for transportation of Federal domain gas to shore may well be greater than the costs which a pipeline company would incur. In cases where the supply of gas is relatively small and not close to other sources of supply a pipeline company might be unwilling to build a small diameter (and therefore high unit cost) pipeline to reach the supply. Certainly, it would not be willing to build a larger pipeline which could not be fully utilized.

If the producer, in order to market his gas, is compelled to build a small diameter pipeline which can transport the gas only at a much higher unit cost than a fully utilized large diameter pipeline would incur,[17] it is questionable whether it is in the public interest to allow the full cost of such high cost transportation to be added to the price which the producer may charge for its gas. It is also questionable whether any such costs should be part of the just and reasonable price or whether the gas should be held to be of lesser value by reason of the difficulty and expense of getting it to the pipeline. It may be argued that the fact that other gas is available at the onshore rates should operate to limit the just and reasonable price for gas delivered onshore to an

[17] There are, of course, the other factors which can operate to raise the unit cost of transporting gas, *e.g.* where the location of the line was planned for sole benefit of the producer, whether the gas capacity of the line is reduced by reason of the transportation of liquids, etc.

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amount no greater than these onshore rates even though the cost of transportation plus the applicable Federal domain rates would exceed the rates which would be charged for gas produced onshore.

We decide none of these issues here. These questions should be determined on the basis of the facts in the particular cases. It was for this reason that we stated in Opinion No. 546 that petitions for special relief may be filed by individual producers setting forth their particular circumstances in each case. Amerada, *et al.* have correctly pointed out, however, that if a producer is limited to the Federal domain applicable rate during the period his petition is being considered, and it is thereafter determined that an increment should be added to that rate, the producer will have lost irrecoverably the increment with respect to all gas sold during the pendency of the petition. They ask, therefore, that a producer be allowed to collect the higher onshore rate pending a decision on the petition. If it were found that a producer was not entitled to all or any part of the 1.5 cent differential between Federal domain and onshore prices, the excess collections could be refunded.

To issue now a general order permitting collection of the onshore rates by all producers who sell Federal domain gas onshore would mean that those who may be dilatory in filing their petitions

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could collect the onshore rate for an unreasonably long period of time. This would be especially undesirable in cases where the facts to be presented would make it obvious that the full 1.5 cent differential between Federal domain and onshore prices would not be allowed the producer. Nevertheless, we think the producers should be protected against

irrecoverable loss if they act with diligence. Accordingly, this order will provide that any producer who, within 30 days of the date of this order, files a petition for special relief by reason of the fact that it is transporting, or paying for transportation of, Federal domain gas to shore may collect the applicable onshore rate. Such collection will be subject to refund of all or any part of the 1.5-cent differential to which the producer ultimately is found not to be entitled. The authorization to collect the higher rate will continue until the Commission has acted upon the petition or otherwise orders. All such petitions should set forth in detail the facts in each case including the amount of the underlying reserves, the unit cost of transportation and the basis for determining that unit cost, the size and capacity of the pipeline utilized, the ownership of the gas carried by the line,[18] the extent to which liquids are carried by the facility and the details with respect to onshore processing of the gas carried, including the compensation received for liquids, entrained or otherwise. The Commission may, prior to its ultimate decision on the merits, reduce the price which may be collected during the pendency of the application to a lesser amount than the applicable onshore price if it appears that the producer cannot justify the full 1.5 cent differential between the onshore and Federal domain prices.

As discussed above, any producer selling gas produced in the Federal domain under a third-vintage contract may file for and collect the 20-cent onshore base rate pending the conclusion of the new investigation initiated in Docket No. AR69-1. Based on the results thereof, producers making such filings either will be permitted to retain the full 20 cents per Mcf collected or will be required to refund all or

[18] Where more than one stream of gas is carried the producer should indicate the relative proportion, ownership and distances transported.

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part of the 1.5-cent increment between the onshore and offshore base rates. As of this time no contracts have been filed where a producer is

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transporting gas onshore from the Federal domain under a third vintage contract. Should any such contracts be filed, the Commission will consider whether an additional amount should be allowed for the transportation service provided.

Union Oil Company of California (Union) has filed a supplemental motion for clarification or rehearing with respect to its sales to Tennessee from the Rollover Field, in the Federal domain offshore Louisiana, which are transported onshore by the Jupiter Corporation (Jupiter) at Union's expense. Union's motion is, in essence, the type of petition for special relief which we invited. As a result of the extensive proceedings which have already occurred with respect to this particular transaction,[19] we are prepared to act on Union's petition now. A Section 5(a) proceeding involving Jupiter was settled in 1966 on the basis of a 1-cent per Mcf charge to Union for the gas transported by Jupiter for delivery to Tennessee, 35 FPC 1091, and Jupiter, in compliance therewith, filed on July 13, 1966, a rate schedule (effective May 15, 1966) calling for a 1-cent per Mcf rate for transporting Union's gas to Tennessee. Thus Union will be allowed to receive up to the applicable 17.0 cents per Mcf Federal domain base area rate, with appropriate Btu adjustments, if any, plus the actual trans-

[19] *The Jupiter Corporation*, Docket Nos. RI63-212 and G-16790, Order Approving Rate Settlement, etc., 35 FPC 1091; Order Clarifying Prior Order and Denying Rehearing, 36 FPC 495; Order on Petitions for Declaratory Relief, 39 FPC 417, issued April 3, 1968; rehearing denied, 39 FPC ....., issued May 24, 1968.

portation charge paid to Jupiter under Jupiter's rate schedule No. 7 for the gas delivered to Tennessee, currently 1 cent per Mcf.

Union is presently seeking review of our determination in the April 3, 1968, order, *supra*, that, under the rate settlement entered into by its predecessor, Pure Oil Co. (28 FPC 889), it is entitled only to the one cent allowed Jupiter for the transportation of Union's gas to Tennessee; it claims it is entitled to receive from Tennessee (over and beyond the base price for the gas) whatever sum it is contractually obligated to pay Jupiter, even to the extent that some part of such sum is for services Jupiter performs for Union which do not benefit

Tennessee.[20] Whatever the outcome of this court proceeding, the terms of the settlement are in any event only applicable up to the effective date of the Section 5(a) order in the present proceeding, which is, of course, prospectively applicable to Union's sale to Tennessee like all others of its Southern Louisiana sales. In light of the pending litigation, however, we shall not order Union to make any of the refunds it would otherwise be required to make for the period prior to the effective date of Opinion No. 546 until its full obligations during the earlier period have been finally adjudicated.

Delivery Pressure

Opinion No. 546 (mimeo pages 87-8, 146) prescribed a quality standard, applicable to gas sold under contracts dated on or after October 1, 1968, relating to gas delivery pressure. The quality standard for pipeline quality gas was framed as follows (mimeo page 146):

[20] *Union Oil Company of California* v. *F.P.C.*, CADC No. 22,442.

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Delivery Pressure — The gas shall be delivered at a pressure sufficient to enter the buyer's pipeline except that a minimum of 800 psig must be available at the point of delivery.

Rehearing is sought as to the 800 psig minimum by the Pipeline Group, Tennessee Gas Pipeline Company, a Division of Tenneco, Inc., and certain Distributor Interveners. The Pipeline Group and the Distributors object that 800 psig is too low in light of the evidence and conditions applicable to the Southern Louisiana area, that virtually all contracts in the area have provided for a minimum pressure of 1,000 psig, and that if a standard is to be fixed it should be no lower than the 1,000 psig predominant contract standard. The Pipeline Group also advises that "some of the pipelines believe that a pressure level above 1,000 psig would be warranted for production from the offshore area," and that adherence to an 800 psig standard may be expected to increase the cost of pipeline supply and transmission facilities. Tennessee urges that the applicable area rate not be reduced in the case of a sale of gas deliverable at less than the standard pressure if the buyer has no use for higher pressure gas at the delivery point.

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We conclude that reconsideration and clarification is in order.

The quality standard provision of Opinion No. 546 should be examined in light of the precedent of the *Permian Basin* case. In the Permian Basin area, most of the production was casinghead (oil-well) gas flowing from the oil well at pressures only slightly in excess of atmospheric pressure.[21]

[21] The gas-well gas in the area was generally delivered at higher pressures than the typical low-quality casinghead gas. 34 FPC at 366.

There, most of the casinghead gas was gathered by gasoline plant operators and compressed by them through one, two or three stages of compression. Much of the gas was compressed through only one stage and delivered to pipeline companies at pressures as low as 50 psig. 34 FPC at 366. Large volumes of residue gas were also delivered after three stages of compression at gasoline plants at substantially higher pressures, often as high as 500-600 psig, sometimes higher. Private bargaining practices has established price differentials between low pressure and high pressure sales of plant residue gas. The Examiner found that imposition of a pressure standard was necessary to prevent degradation of quality in reaction to the price reductions to be ordered by the Commission in the

Permian Basin. 34 FPC at 366. The Commission fixed 500 psig as the pressure standard for pipeline quality gas in the Permian Basin. 34 FPC at 1070.[22]

In *Permian*, also, the Commission expressed its standard in terms of *actual delivery* pressure,[23] but limited the impact

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[22] The Examiner would have fixed price differentials, for plant residue gas only, based on whether the plant operation supplied three-stage, two-stage or only one-stage of compression. 34 FPC at 370. The Commission expressed the standards as a specified pressure and expanded its coverage to all gas deliveries. The Commission initially picked a standard of 800 psig based on the pressure generally employed in the principal mainline segment of the pipelines taking gas out of the Permian Basin area. 34 FPC 224. On rehearing, however, the Commission revised the standard to 500 psig to reflect actual delivery standards in the area, as well as the existence of low pressure pipeline systems in the area. The Commission adhered to the view that 800 psig accurately reflected the relevant mainline pressures, but held that "a pressure standard of 500 pounds would more nearly reflect the pressure at which gas is delivered to the pipeline systems in the Permian Basin."

[23] "Pipeline quality gas shall be delivered at a pressure of not less than . . . pounds per square inch." 34 FPC at 240 and 1078.

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of the standard by providing there would be no price adjustment to the extent that the standard exceeded actual delivery pressure on account of the buyer's choosing to take gas at a lower pressure than seller's capability.[24]

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Producers deliver gas in the Southern Louisiana area at substantially higher pressures than do the producers and gasoline plant operators in the Permian Basin area. (Opinion No. 546 finds that actual delivery pressure exceeds 800 psig for over 88 percent of the volumes delivered. Mimeo page 87.) So far as we can determine, virtually all of the Southern Louisiana gas wells initially can produce at pressures far in excess of the highest pipeline operating pressure in the area; wellhead pressures gradually decline (except in the more active water-drive reservoirs) as a result of the cumulative withdrawal of hydrocarbons, but those pressures are not inherently low. Southern Louisiana oil wells, too, initially produce at high pressures; in a few instances the oil-well gas may be separated from crude oil at less than gas pipeline pressures. Nonetheless, the prevailing practice has been for the producer to deliver the oil-well gas at the same pressure as that governing takes of the predominant gas-well gas. The situation here differs, then, from that in *Permian* where low-pressure gas production and low-pressure gathering systems were the predominant source of supply and either buyer or seller had to incur the cost of compression up to desirable pressures.

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[24] "If the seller is ready and able to deliver natural gas into buyers' facilities without further compression, at pressures higher than the pressure at which the buyers' facilities available at the point of delivery can accept such gas, any downward adjustment for the cost of compression shall be limited to the cost of such compression as is incurred to raise the pressure of the gas from the pressure at which the seller is ready and able to deliver it up to the pressure standard of 500 psig." 34 FPC at 1078.

On the other hand, our order here has raised fears on the part of the purchasers that the Commission intends to disrupt established contracting practices in the area. While we may consider the fears unjustified they deserve to be laid to rest. Gas purchase contracts in the area characteristically include an article governing delivery pressure. Such provisions control the point of abandonment of production. When, as a result of declining reservoir pressure, a well can no longer produce against the specified line pressure, then the buyer may reduce the operating pressure of its line; either the buyer or the seller may install compression; or the sale may (upon approval by the Commission) be abandoned. So long as gas can be delivered at the specified contract pressure (or at some higher pressure) seller is obliged to deliver and buyer is obliged to purchase gas. The specified pressure determines when these obligations are to terminate.

Producers frequently deliver gas at pressures higher than those specified in the contracts so long as the wells are capable of doing so. It is in the public interest that this practice

continue since, as the Pipeline Group points out, higher delivery pressure tend to permit handling of greater volumes (and, so, incurrence of lower unit transmission costs) with a given set of pipeline facilities. Nothing in Opinion No. 546 was intended to discourage this practice.

Sales often continue even after the wells can no longer flow against the contract-specified pressure in circumstances where the value of the extra gas to be recovered exceeds the costs of compression (or the diseconomies of operating the gathering systems at lower pressure). Such practices are also in the public interest and should not be disrupted.

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The Pipeline Group expresses the fear that producers will henceforth insist on contract pressures of 800 psig, thus disrupting practices upon which they have planned their systems. Opinion No. 546 was not intended to affect such contract practices. Contract pressure is one of the non-price terms referred to in the next section of this Opinion, which should continue to conform to high quality standards and which will be reviewed in future certificate cases. Given the chance of misinterpretation, however, and considering the operating circumstances in Southern Louisiana, the Commission has determined that the Opinion No. 546 pressure standard of 800 psig should be deleted. Instead, we shall expect producers to deliver their gas at such pressures as buyers request, even in excess of the pressures specified of seller's wells enable such delivery. When the natural flowing pressures of seller's wells decline to, or below, the pressure in buyer's line the relevant contractual rights of buyer and seller will come into play. In many instances, the Commission anticipates that buyer and seller will continue the flow of gas beyond the point at which their contractual obligations terminate.

In the case of oil-well gas, the Commission will continue to require delivery at the same pressures as are made available from gas-wells flowing into the same gathering facilities. Here, as in Opinion No. 468, the Commission has allowed an area rate for oil-well gas based on the costs of flowing gas-well gas for reasons of directional exploration and relative value and notwithstanding the indicated low cost of casinghead gas. The availability evidence indicates that relatively little

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compression of casinghead gas is presently being performed in order to accomplish the delivery of this gas into pipeline gathering systems.

Accordingly, we shall amend ordering paragraph (A), section 154.105(d)(vii) to read:

> (vii) *Delivery Pressure* — The gas shall be delivered at a pressure sufficient to enter the buyer's pipeline, except that when the natural flowing pressue of seller's wells declines to, or below, the level sufficient for such delivery nothing herein shall require seller to deliver gas at a pressure higher than specified by contract.

The foregoing amendment to Opinion No. 546 will have the effect of granting the relief sought by Tennessee as well as by the Pipeline Group and the Distributor Intervenors.

The foregoing pressure standard will apply as a rule only to third-vintage contracts. But application and refinement of the general principles enunciated herein may be considered in any certificate proceedings, including proceedings relating to second-vintage contracts. If experience in applying these principles in certificate proceedings indicates a need, the Commission will revise its general rule.

Non-Price Contract Terms

The Distributor Intervenors urge that "the Commission should make it clear that the non-price provisions of new contracts must conform to a high standard to qualify for the ceiling prices . . ." Non-price provisions include *inter alia* reserve-delivery ratios, take-or-pay or minimum purchase obligations, make-up period, swings, term of contract and, as noted in the previous section, delivery pressure conditions.

The precise standards as to non-price provisions in future contracts must await determination in the certificate

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proceedings as they arise or in rulemaking proceedings. In general, however, the non-price provisions of such contracts should not be less favorable to the purchasers than contracts in the area

have been customarily, unless fully offsetting benefits are provided to compensate the purchasers. What these offsetting benefits may be, and the extent of them, must be left for the particular certificate proceedings.

Gathering Cost Allowance

The New York Commission and the Distributor Intervenors complain about our allowance of 0.51 cents per Mcf in the new gas costing for gathering. In Opinion No. 546 we allowed this amount (in addition to any gathering costs that may be reflected in lease accounts) to cover 0.18 cents for separately reported gathering systems and 0.33 cents for gathering related to producer plants. For reasons explained by the Examiner the 0.18 cents should plainly be allowed. Initial Decision pp. 170-171. The applications for rehearing concentrate on plant related gathering.

The parties' main point in this regard is that plant gathering costs should not be attributed to gas; allegedly the gas is gathered to plant for purposes of liquid extraction and the liquid revenues are ample to recoup plant costs. However, the applicants' calculation of plant revenues fails to reflect the plants' payment of part of the liquid revenues to the lease. It has not been shown, then, that the plants' share of liquid revenues is adequate to cover all plant costs.

However, even if it had been definitely shown that plant liquid revenue covered all plant costs, we cannot here as-

sume that, because the plants may have been built for profitable extraction of liquids, the benefits to gas should be ignored or should run free to gas consumers. Compare *Phillips Petroleum Co.*, 24 FPC 537, 562, affirmed sub nom. *Wisconsin v. F.P.C.*, 373 U.S. 294.

In addition it should be noted that the prices herein established **are for a standard of quality** wherein the delivery point is specified as a central point and includes the tailgate of natural gas processing plants (Opinion No. 546 p. 146). Thus equity would require that all costs be included to the point where the standard requires gas to be delivered to qualify for the prices herein prescribed.

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We are more troubled by other difficulties which we originally noted, Opinion No. 546, pp. 60-61, and which are pressed now on rehearing. Our 0.33 cents for plant gathering includes a full 12 percent return allowance and reflects a straight Btu allocation of costs, an allocation that may allocate more costs to gas than other, possibly preferable methods. However, any excesses in this regard must necessarily be slight; the entire allowance is only 0.33 cents. The amount of possible excess does not seem worth the burden of further hearings on other allocation methods. As for return, assuming for comparision that 10.5 percent were appropriate, the 0.33 cents allowance would drop to 0.31 cents per Mcf. There is no warrant here for the 6 percent return suggested by the Distributor Intervenors. On balance, we believe the gathering cost allowance in the Opinion is amply justified.

Rate of Return

The New York Public Service Commission, the MGD Group and the Amerada and Hunt Group of producers

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attack our rate of return determination as either too high or too low. The principal arguments were considered in our original Opinion. Some of the producers' contentions are based on extra record data and publications, which are improperly relied on at this late stage in the proceedings. We need deal at this point with only two of the contentions concerning rate of return, both made by the producers.

The Amerada Group producers contend that our reliance on 1958-62 earnings data is erroneous. They claim we should rely both on older data and on more recent data. The older data is outdated for fixing the rate of return here. As for recent data, the producers do not cite any recent earnings data that would demonstrate our return allowance to be too low. In light of the claims in their application for rehearing, we have

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updated the earnings data for non-integrated producers reflected in staff witness Shaffner's studies referred to at page 48 of Opinion No. 546. For the years 1962-66, the nine companies included in his sample have declined to seven companies. The simple average return for these seven companies is 11.7 percent for the recent years whereas it had been 12.1 percent for the earlier five year period for the nine companies. The average return for the seven companies, weighted according to their 1966 capitalization, was 12 percent for the recent period whereas the weighted average had been 11.7 for the previous five year period for the nine companies. The producers complain that two of the remaining seven companies should not be included in the non-integrated sample. Exclusion of those two companies would raise the 1962-66 data to 12.5 percent for both the simple and weighted average. Those averages, however,

would reflect only five companies now and would include some unrepresentatively high earnings rate such as Amerada's 20.4 percent. In our view the more recent data in no way demonstrates the producers' contention that subsequent earnings data warrant higher than a 12 percent return allowance.

The producers also assert that the questionnaire responses reveal that the integrated producers earned 14.3 percent on their domestic production departments for the year 1960. The producers cite no evidence that would warrant our relying on their calculation. In the *Permian* case the Examiner noted some of the difficulties in dealing with departmental earnings. 34 FPC 346. In our Opinion in this case we found (pp. 48-49) that the record evidence is deficient in this area. Two recent Examiners' decisions also deal with some of the problems of determining production department earnings: Examiners decisions, issued September 16, 1968, Docket No. AR64-1, pages 131-134 and AR64-2, pages 140-144. We do not mean to prejudge those decisions by here accepting or rejecting what the Examiners had to say on the issue. But, neither do we wish to prejudge the matter by simply accepting the producers' calculation, without any evidentiary support and explanation, in this very complicated area.

In conclusion, we find nothing in the application for rehearing that would warrant our changing the rate of return allowances reflected in the rates approved in this proceeding.

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New Gas-Well Gas: Applicability of National Unit Costs to Southern Louisiana

Contrary to the assertions in the applications for rehearing filed by the Amerada Group and The California Com-

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pany, Southern Louisiana unit costs have not been shown to be significantly higher than nationwide costs. Consequently, no upward adjustment is required to translate the computed nationwide cost into the area ceiling rate for second and third vintage gas-well gas. The basis for the respondent's claim that the use of national costs as a proxy for the area new gas cost is improper is the same contained in the Amerada Group's reply brief and fully answered by the Examiner (pp. 118-123). Although lease acquisition and rental costs, geological and geophysical expenses, production operating expense, and area royalty appear higher in Southern Louisiana than nationwide, other area costs, notably successful well and dry hole costs, when computed on the basis of the amount of reserves added for the expenditures incurred, are either the same as or slightly under national costs. The area liquid realization, however, is substantially higher for Southern Louisiana than for the nation as a whole. While the net liquid credit in the new gas costing in the Opinion is 3.30 cents per Mcf, the area liquid credit derived from the 1962 all-area questionnaire exceeds six cents per Mcf.[25] This difference is more than adequate to counter-balance those items where area costs are above the national average.

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New Gas-Well Gas: Discounted Cash Flow Method

The Amerada Group of producers criticize our application of the DCF method in Appendix D of Opinion No. 546. Far from corroborating our analysis of new gas costs, the producers say, the three mill deficiency in Appendix D really shows that our cost allowances afford barely an 11

[25] Application For Rehearing Of Indicated Respondents (Amerada Group), Appendix B-3.

percent return and not the intended 12 percent. However, Opinion No. 546 observes that the three mills would be more than offset by timing considerations and the introduction of an interest deduction (mimeo p. 14); in our opinion there is no deficiency.

Appendix C herein recalculates the DCF test to include an interest deduction of 0.32 cents in the tax calculation. This tax deduction equals 4.5 percent interest on debt financing for about 15 percent of the rate base. See Opinion No. 546, page 50. The interest might well be more than 0.32 cents per Mcf. The deduction is distributed *pro rata* the investment outlays. The net overall effect is to reduce the apparent deficiency from three mills to 0.138630 cents. Furthermore, Appendix D exaggerated timing considerations in the producers' favor. For example, producers often receive prepayments for gas before the pipelines receive the volumes paid for. Yet Appendix D reflects lag and revenues according to the timing of production rather than the earlier time of actual receipts by producers. See also Opinion No. 546, Appendix B, pages 4-7. Although we cannot measure the effect precisely, true timing considerations would further mitigate if not eliminate the seeming deficiency in Appendix D.

New Gas-Well Gas: Time Lag

The Amerada Group producers here argue (Application for rehearing pp. 50-52 and Appendix C-5), as they did in their exceptions, for a 2½-year time lag allowance, and criticize Opinion No. 546 for alleged errors in the findings supporting the one-year lag allowance there adopted. The Amerada Group continues to rely principally on the Auten-Davis study, specially compiled for the producers and presented in evidence by the Amerada Group.

Opinion No. 546 upheld the Examiner's findings and conclusion that the Auten-Davis data are not reliable proof and tend to exaggerate lags. The Commission, therefore, did not base its time lag allowance on these data. Nonetheless, Opinion No. 546 used the Auten-Davis data in two respects, *arguendo*, as corroborative of the end result against the criticisms levied by the sponsors of these data: First, Opinion No. 546 found (at pp. 38-40) that the Auten Davis investment data in themselves indicate a one-year pre-production lag. Second, Opinion No. 546 used these data in its Appendices C and D, involving full timing studies which confirmed the end result of the simplified, basic costing model.[26] Amerada Group has no quarrel with the latter uses of the Auten-Davis investment data; its criticism goes to the former findings.

The Amerada Group would correct the table at p. 40 of Opinion No. 546 and related text to derive a pre-production time lag of 1.57 years.[27] Opinion No. 546 derived an average time lag weighted for the actual investment categories

[26] These data are again so used in Appendix C to this Opinion No. 546-A.

[27] They would also add a further, 1.12-year lag for production buildup, also based on the Auten-Davis survey discredited by the Examiner, to arrive at an overall 2½-year time lag. The Commission's basic cost findings instead adhere to the Examiner's simplified model, which assumes full production (or, more precisely, a full revenue stream) in the first productive year. However, as the Amerada Group itself observes, the full timing studies used to check the end result do include an estimated production buildup (presented by witness Rosenan and incorporated by reference from the *Permian Basin* case).

and amounts reported in the Auten-Davis study; the Amerada Group urges that the timing results for each investment category should have been weighted instead by the cost components independently found and allowed in Opinion No. 546 by the weighting procedure followed in Appendices C and D to that Opinion.[28] This correction is called for. Standing alone, it has a relatively minor impact on the time lag computation.[29]

The Amerada Group also criticizes and amends the computations in the table and discussion at pages 39 and 40 of Opinion No. 546 (as contrasted with Appendices C and D to the Opinion) with respect to the investment timing pattern reported by the Auten-Davis survey. The issue turns on interpretation of the yearly data presented by the Auten-Davis study, and the appropriate assumptions regarding timing within the year. In essence, the Opinion No. 546 computation assumed (a) that the investments reported for a given year were made continuously throughout that year and should be treated as made, on the average, at mid-year; but (b) that the initial production occurred at the start of the year of first production. The Amerada Group follows the first assumption, but would place the

[28] The investment reported in the Auten-Davis study totals approximately $68 million, broken down into lease acquisitions ($10 million), productive wildcats ($18 million), and successful development wells plus related facilities ($40 million). The investment cost components in Opinion No. 546 are lease acquisitions (0.76 cents/Mcf), successful well costs (2.88 cents/Mcf), and other production facilities (0.40 cents/Mcf).

[29] Opinion No. 546 computed an effective center of the Auten-Davis investment outlay at January 11, 1959; had the computation been weighted for the Commission's cost components the effective center of investment would have been December 7, 1958, a difference of 35 days.

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relevant center of first year production at the mid-point of that first year, *i.e.*, six months later than the criticized portion of Opinion No. 546. The record before us does not fully explore this matter. However, it appears that the relevant measure within the four corners of the Auten Davis survey is more probably the mid-year point as used by the

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Amerada Group, and that a correction to Opinion No. 546 is in order on this score.

Accordingly, we amend our findings to recognize that the Auten-Davis investment data, in themselves, compute to a 1.57-year pre-production lag. Nonetheless, in view of the exaggerations found in the Auten-Davis survey and since the Opinion No. 546 end result is still confirmed by the full timing studies, there is no reason to raise the Commission's basic cost findings.

The Amerada Group finally suggests that a lag allowance of 2½ years is independently validated by data from the Commission's own Appendices B and C cost surveys. As the Amerada Group points out, Opinion No. 546 relied on these data to support the conclusion that an initial gross investment amounting to 20 times the annual depletion, depreciation, and amortization (DD&A) of production investment costs is adequate, or more than adequate. (Opinion No. 546, p. 37): Reported national gross investment in producing leases was 18 times the annual DD&A for those leases. Now, the Amerada Group contends, the Commission should note that the comparable national investment in shut-in gas leases is 2½ to 3 times the same annual DD&A, and therefore allow a 2½-year time lag in the basic new gas costing.[20] The contention is ill founded. The shut-in investment is not

related to the DD&A on producing leases. The 18:1 relationship properly compared the gross investment in producing gas reserves with DD&A of that same investment. But the 2½:1 (or 3:1) relationship compared gross investment in other, shut-in gas reserves with the unrelated DD&A attributable to production from the producing gas reserves. The second comparison involves two unrelated things.[31]

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For the foregoing reasons, we do not disturb the one-year time lag as employed in the basic costing of Opinion No. 546. We reiterate, however, our desire that in future area rate proceedings, and particularly in the first second-round proceeding, being instituted simultaneously herewith, the parties and the staff work together to secure a more reliable empirical foundation for resolving the time lag question.

Federal Income Tax

At pages 42-43 of its application for rehearing, the Amerada Group complains that the Commission has been inconsistent in not allowing a federal income tax liability when "in both of its discounted cash flow studies, the Commission computed an income tax liability." As we explained

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[30] Were we to base the new gas costing directly on these relations, the rate base would be 11½ or 12 times the DD&A (11½ equals the sum of 2½ for lag plus half of 18 for average outstanding investment) rather than 11 times as employed in Opinion No. 546.

[31] The comparison might be significant if the producers had presented the gas reserves volumes associated with the shut-in and with the productive investments; if there had been no growth in reserves from vintage to vintage (or year to year) reflected in those investments, and if the investment per Mcf of shut-in reserves were the same as the investment per Mcf of the producing reserves. But none of these demonstrations has been made.

at p. 57 of our Opinion, we cannot make a finding that the industry as a whole pays Federal income taxes on exploratory and production activities absent evidentiary support that such a tax would be actually paid based upon Federal income tax return data. This data is clearly available to respondents. Thus, any tax determination which we might derive would lack requisite record support. With regard to our alleged inconsistency, we are aware of the computed tax shown in the discounted cash flow calculations. However, as we specifically pointed out at appendix page B-9 of our Opinion, these tax computations are not necessarily reflective of taxes which respondents will have to pay. Federal income tax determinations on an individual company basis result in a balancing of various revenue receipts and expenditures not necessarily shown by our discounted cash flow computations. One example of this, mentioned in our Opinion, is the deductibility for Federal income tax purposes of interest expense. While the Amerada Group's brief claims that such deduction would be *de minimus*, the very failure of the main body of respondents who are joined in the Amerada filing to present evidence of their own income tax payments prevents proof of the assertions which Amerada makes. Moreover, as we specifically recognized, one of the reasons for the industry's avoidance of tax are the relatively large amounts of deductions available during the time of incurrence of initial investments in production. Thus, in an expanding industry, investments in new producing facilities would counterbalance possible tax liabilities on older, more depleted, investments. Compare *Alabama Tennessee Natural Gas Co.*, 31 FPC 208 (1964), affirmed, 359 F. 2d 318 (CA5, 1966), *certiorari denied*, 385 U.S. 847 (1966). Our discounted cash flow studies show one hypothetical property and not the interplay of many properties.

The Amerada Group contends, however, that Opinion No. 546 is internally inconsistent advancing "the growth of the industry as a factor operating to free producers of income taxes and simultaneously deny an allowance for growth in the rate base." We believe both conclusions are sound since our purpose is to estimate the costs actually incurred: The claimed "growth in the rate base" is a capitalized, long-term investment which our costing properly assigns against the extra volumes to be produced from gas reserves found and developed by that investment; it would be improper to assign that extra investment against production from the earlier reserve additions. On the other hand, there is no reason to asesign a tax cost against production where the deductions permitted by the tax laws eliminate actual tax cost. The tax laws treat intangible development costs of successful wells as a current expense in the year incurred, whereas Opinion No. 546 capitalizes these I.D.C. costs and associates them with future production. This difference may well reflect an inconsistency between the economic or accounting analysis of I.D.C. costs implicit in the tax laws and that of Opinion No. 546. But such an inconsistency is irrelevant here since it is the actual tax cost, rather than the tax accounting principle on which our decision turns. The situation is analogous to the liberalized depreciation deduction allowed by the tax laws, where the Commission has allowed a lower tax cost in a pipeline company cost-of-service even though a straight-line, book depreciation cost is taken in that same cost-of-service.

The main point is that the discounted cash flow studies are not meant to supplant our principal cost findings. Absent probative direct evidence that a tax would be

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paid, we are required to deny a Federal income tax allowance in these proceedings.

First Vintage Gas-Well Gas; Allocation of Costs Between Gas and Liquids

The Amerada Group claims that the Commission's allocation of costs for flowing gas-well gas contracted for prior to January 1, 1961 is arbitrary in terms of end result in that the costs allocated to liquids are greater than the revenues they actually recovered for such liquids in 1960. The reason for this apparent anomaly is that the "costs" include the return on shut-in properties, and, as of 1960, 25.2 percent of all Southern Louisiana gas lease investment was in shut-in properties (with the figure being 12.3 percent

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nationally exclusive of Southern Louisiana.) Assuming that the liquid revenues from the producing acreage may have been inadequate to cover the liquid costs, including the portion of shut-in investment costs attributable to liquids, it does not follow that this deficiency for liquids (which presumably may no longer exist as the shut-in properties begin production) should be made up by increased gas prices. The situation is not comparable to that applicable to gas-well gas under contracts after 1960, where the ability to explore directionally for gas, and the public interest in inducing such exploration, justifies a liquid crediting technique in which gas consumers would pay for any liquid costs not actually recovered.

Refund Provisions

The California Co. in its application for rehearing urges that Ordering Paragraph (C) accompanying Opinion No.

546 should be amended. Paragraph (C) states in relevant part, "no refunds are required below the rate allowed in a final, *unconditioned* permanent certificate previously granted for such sale." (Emphasis supplied.) Calco points out that every certificate contains conditions having no relation to refunds, and suggests that the language of Paragraph (C) be amended to read "no refunds are required below the rate allowed by final order permanently certificating the sale in question and containing no refund condition." We agree with Calco that Paragraph (C) should be amended to make clear that only *refund* conditions in a permanent certificate would operate to allow refunds below the rate provided in such certificate, and our order herein will so provide.

The Shell, Mobil and Sinclair supplemental applications for rehearing contend that where settlement has been agreed upon in Section 4(e) cases and, as part of the settlement, refunds were also agreed upon, the settlement rate constitutes a floor below which refunds should not be ordered. Texaco Inc. argues that this issue is not raised by any of the dockets in this proceeding, and neither should nor can be decided here.

Section 4(e) cases which have been settled are not properly included in the present proceedings. They have been terminated and, unless the question of refunds was excluded from the settlement, any refund obligations under such Section 4(e) cases are established by the settlement.

In the instance of one consolidated section 4(e) proceeding (General American Oil Company of Texas, Docket No. RI61-321) the just and reasonable base rate has been determined to be 18.5 cents per Mcf whereas, for at least

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some of the gas sold under the relevant rate schedule No. 42 of General American, a settlement rate of 19.25 cents per Mcf was approved by final Commission order. (John W. Mecom, 25 FPC 1022, order accepting offer of settlement and providing for refunds, issued May 25, 1961). In preparing its refund report pursuant to ordering paragraph (F) of Opinion No. 546, General American should reflect the difference between the rate collected pursuant to Docket No. RI61-321 (i.e., 22.25 cents per Mcf) and the settlement rate (19.25 cents per Mcf) applied to the volumes sold to which that settlement rate would have applied but for the section 4(e) filing consolidated herewith. Commencing with the effective date of Opinion No. 546, General American will be limited, of course, to the 18.5 cent area rate, plus Btu adjustment if any, for all further deliveries of gas sold under rate schedule No. 42.

General American moved on October 17, 1968, to clarify the refund requirements. On October 21 and 25, respectively, Continental and Sinclair adopted that motion. Movants contend that refunds should not only be limited to the amount of any increase involved in a Section 4(e) proceeding, but where sales are made under a temporary certificate refunds should be ordered only of amounts collected above the in-line price. General American cites the consolidated section 4(e) proceeding in Docket No. RI62-392 involving its Rate Schedule No. 63. In that case General American has been collecting 22 cents per Mcf subject to refund. However, the Commission issued a *permanent* certificate (to General American's predecessor, J. P. Owen) by Opinion No. 436 (*Union Texas Petroleum*, 32 FPC 254.[32]) ap-

[32] The order was not appealed as to this sale but review was sought by other producers as to other issues. *Pan American Petroleum Corp.*, v. *F.P.C.*, 376 F. 2d 161 (CA10, 1967) remanding Opinion No. 436, order on remand issued December 18, 1968, *Union Texas Petroleum, et al.*, 40 FPC .....

proving the proposed initial rate of 20 cents per Mcf. Thus 20 cents per Mcf constitutes a refund floor in Docket No. R162-392. If other section 4(e) proceedings consolidated herewith involve temporarily certificated sales, any questions regarding the appropriate refund calculation

should be presented concretely in the context of the facts of each sale. The Commission will not pass now on these questions in the abstract, but will deny the motion without prejudice.

Scope of Commission Order

The Amerada Group states (Application for Rehearing pages 89-90) that "Prejudgment of matters pending in other pending proceedings, indicated by the *last paragraph on page 110 of Opinion No. 546* is unlawful, denies required hearings under Sections 7 and 4 of the Act, and denies procedural and substantive due process of law." The paragraph referred to reads:

> "Since just and reasonable rates are fixed herein for all producers in the area by virtue of the rules established in this proceeding, permanent certificates for all pending applications may now be granted."

We agree with the Amerada Group that the Commission can not determine in this proceeding the outcome of certificate cases not consolidated herein. Although Opinion No. 546 resolves some issues in such cases,[33] the area rate decision does not automatically resolve all certificate issues, including the appropriate refunds for past periods of opera-

[33] *Phillips Petroleum Co., et al. v. F.P.C.* .... F. 2d .... (CA10, Nos. 8723, 8778 and 8808, issued January 2, 1969).

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tion under temporary certificates, and we hereby correct any intimation to the contrary.

Interest on Royalty Payments to Federal and State Governments

We agree with The California Company that, in accordance with the provision of Section 154.102(f) of the Regulations Under the Natural Gas Act, no interest should be required on refundable amounts paid over to the Federal and State governments in royalties, except as and to the extent that such authorities pay interest to the producer when refunding overpayments of royalties. The order accompanying this Opinion will so provide.

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Prime Interest Rate for Certain Refunds

The Amerada Group opposes the 6.5 percent interest required by Ordering Paragraph (G) on refund amounts which are retained by a producer and commingled with its general assets. The filing points out that the prime rate subsequently was reduced to 6.25 percent and asserts that this rate should be substituted for the 6.5 per cent. Calco likewise contends that the specified rate is excessive and should be reduced. The interest rate required on retained, commingled refund monies is the prime rate at the time of issuance of the Opinion or Order giving rise to the refund obligation, in this case September 25, 1968.[34] The Amerada Group, in their application for rehearing, acknowledge that 6.5 percent "reflects the prime interest rate as of the date of issuance of Opinion No. 546." Consequently, there is no basis for a change in the rate established in the Opinion.

[34] The prime interest rate has since gone up to 7 percent.

Amerada further contends that interest on refunds required under Ordering Paragraph (F) should not be calculated to the date of filing of the refund report, as is now provided, but to the last day of the month preceding the month in which the refund report is required. We shall accept this modification for the reason stated by Amerada and to provide consistent treatment with our disposition of the similar item in *Permian*. See *Area Rate Proceeding, et al.*, Docket Nos. AR61-1, *et al.*, Order Implementing Opinion Nos. 468 and 468-A, issued August 9, 1968.

Escrow and Withholding Practices Relating to State Production Taxes

Some confusion has arisen concerning footnote 40 on page 59 of Opinion No. 546 and clarification appears called for. It was and is our intention that present industry practices with relation to the escrowing or withholding of State production tax reimbursement funds by pipeline purchasers of gas in the disputed areas should be continued pending resolution of the jurisdictional question finally determining the areas in the Federal domain. No change in these practices was intended or should be effected at this time.

Tennessee Gas Pipeline Company's Request For Clarification

Tennessee Gas Pipeline Company has asked for clarification of three matters: (a) the treatment accorded small producers; (b) the definition of gas-cap gas; and (c) the significance of the requirement in section 8.F. of the quality statement that where more than one type or vintage of gas is sold under a rate schedule, the various "proportions" of each be shown. We consider these matters seriatim.

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(a) Small producers — In order to qualify as a "small producer" and receive a small producer certificate the producer must initially make the filings required under Section 157.40(b) of the Regulations Under the Natural Gas Act.[35] After a small producer certificate has been issued, a producer may collect with respect to first and second vintage gas produced in Southern Louisiana, the applicable base area rate, plus upward Btu adjustment, if any.[36] As to third vintage gas in Southern Louisiana, however, a producer may collect the applicable base area rate, but is not entitled to collect any upward Btu adjustment unless he files a quality statement applicable to such sale reflecting all of the quality adjustments specified in the Opinion. If the quality statement is accepted, the producer will then be allowed to collect the rate reflected therein.

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Where a small producer's interest is being sold under a large producer's contract, and the small producer has elected not to claim an upward Btu adjustment, the small producer is entitled to receive the base area rate unadjusted for quality deficiency, irrespective of the rate to which the large producer is entitled. While there may be, as Tennessee notes, problems of appropriate payment,

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[35] Opinion No. 546 (mimeo, p. 97) provided that any producer who has received a small producer certification under the *Permian* decision will have his certificate extended on application to cover his Southern Louisiana sales. Upon further consideration we conclude that there is no need to require any new filing in these circumstances. All previously issued small producer certificates covering sales in the *Permian* area will be deemed without further order to also cover sales in the Southern Louisiana area at prices no higher than those prescribed in Section 157.40 of the Regulations.

[36] The rate collected, of course, cannot exceed the rate provided in the applicable contract.

we believe these will be able to be worked out between the parties. Any disagreements involving the small producer certificates which cannot be resolved by the parties can be referred to the Commission for determination.

(b) Gas-cap gas—Gas-cap gas is defined for the purpose of the Opinion as free natural gas which overlies and is in contact with crude oil in the reservoir but is produced independently of the oil.

(c) Quality statement, section 8.F.,—Tennessee Gas Pipeline Company requested clarification of the purpose for section 8.F. of the Rate Schedule Quality Statement which pertains to the proportion of gas purchased at each applicable rate under the rate schedule and also that the base period for such proportions be specified. The purpose for section 8.F. is to provide information by which the Commission can determine the approximate volume of gas sold by type of gas at each applicable rate. We recognize that sales volumes do not remain constant. The proportions reported in section 8.F. should therefore represent the average or typical mix for the most recent annual period or, for new sales, the estimated annual mix for the first year deliveries.

Effect on Docket No. RP66-24 Proceeding

The Municipal Gas Distributors Group states that the Commisssion erred in not including a finding "that its decision is not controlling as to disposition of any issue before the Presiding Examiner" in the *Pipeline Production Area Rate Proceeding*, Docket No. RP66-24. The *Pipeline Production Area Rate Proceeding* is an investigatory hearing to determine "(W)hether the Commission may or should depart from the cost-of-service method in fixing

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the price of pipeline produced gas . . .," *Area Rate Proceeding (Hugoton-Anadarko)*, Docket No. AR64-1, and *Pipeline Production Area Rate Proceeding*, Docket No. RP66-24, 35 FPC 497 (1966). Thus, the Presiding Examiner, in the first instance, and this Commission will decide whether, in determining pipeline rates, the Commission should depart from its present policy of costing pipeline and pipeline-affiliated produced gas on a cost-of-service basis.

The Municipal Gas Distributor Group has actively participated in the *Pipeline Production Area Rate Proceeding*. If it wishes assurance that we have no intention of prejudging the outcome of issues there involved, we categorically state that this is the case. Nothing decided herein is meant to prejudge issues there to be decided. Of course, this would be the case either with or without a special finding to that effect. This is not to say that, as a result of the determinations reached in Docket No. RP66-24, the rates herein established might not, by decision in that case, be made partially or totally applicable to production by a pipeline or a pipeline affiliate. Nor do we mean to imply that precedents evolved in determining applicable rates for independently produced gas in Docket No. AR61-2, *et al.* may not have relevancy in determining the allowances to be made for pipeline production either as a result of the *Pipeline Production Area Rate Proceeding* or in determining the amounts to be allowed a pipeline or a pipeline affiliate in the context of other individual pipeline rate proceedings. With regard to off-system sales made by a pipeline producer, we will continue the policy established in the *Union Producing* case, Opinion Nos. 414 and 414-A, 31 FPC 41, 503 (1964), pending reconsideration of the issue in the *Pipeline Production Area Rate Proceeding*.

Hunt Motion to Reopen

The application for rehearing filed by the Hunt Group includes a motion to reopen the record for the receipt of certain "newly discovered evidence" and asserts error in our denial of a previous petition which sought to introduce the same material. The motion is opposed in a response filed by the Associated Gas Distributors (AGD). The showings that Hunt proposes by the excluded exhibits are the same as those listed in the Examiner's decision and in the appendices to its brief on exceptions and previously considered by us in all respects. The basic error charged relates to the flowing gas historical cost-of-service studies and the application of Continental U.S. oil and gas leg relative cost ratios in allocating Southern Louisiana joint production costs. The evidence consists of exhibit material prepared on the basis of responses to the All Area Questionnaire, reporting costs, volumes and revenues for a 1962 test year, issued for use in the Docket Nos. AR64-1 and AR64-2 area proceedings.[31]

The *Southern Louisiana Area Rate Proceeding* was instituted on the basis of a 1960 test year and the Appendix A, B and C questionnaire forms issued in the case called

[37] A similar contention is presented by the Amerada Group application (p. 80), except that the Amerada Group also argues that consideration of the excluded exhibits is requisite to overcome matters officially noticed and conclusions reached at pages 130 and 141 of Opinion No. 546. At page 141 we took notice of filed rate schedules to estimate the annual impact of the rates previously and independently fixed; the facts noticed were not dispositive, and so prejudiced no party. Similarly, the updated statistics noticed at pages 133-4 of the Opinion were not dispositive and could have been omitted. In other respects our disposition of the Hunt motion also applies to the Amerada Group contention.

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for data for the test year 1960. The entire case was tried on the basis of a 1960 test year with respect to the flowing gas cost determination based upon a historical cost-of-service. Although the Hunt Group disavows any intention to stay the instant proceeding, it is obvious that the granting of the petition to reopen would require retrial of the flowing gas aspect of the proceeding on the basis of a new 1962 test year. Such a retrial of the case, even if performed in October 1965 when some of the material first offered, would have made a shamble of the administrative process. The fact that the material has been received into evidence in the Docket Nos. AR64-1 and AR64-2 proceedings and has been cross-examined therein provides no basis for the contention that the facts set forth in these exhibits are thereby true and correct and

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that the exhibits should be received in evidence here. In fact, AGD in its filing disputes Hunt's statement that there is no disagreement with the facts presented by it. Accordingly, the Hunt motion will again be denied. However, it should be noted that in Opinion No. 546 we stated that "the Commission will at all times be open to a petition to waive or lift the limitation on rate charge filings in light of changed circumstances." If respondents, including Hunt, determine to file such a petition, they will not be precluded from contending that the matters referred to in the Hunt motion, as well as any other matters, allegedly constitute "changed circumstances." The Commission will then consider the petition, and any replies thereto, as of the time of its filing and determine the action, if any, required to be taken at that time.

Requests For Stay of Order

A number of the producers[38] have requested stay of some or all of the ordering paragraphs of Opinion No. 546 until after the completion of contemplated judicial review proceedings. Section 19(c) of the Natural Gas Act makes it clear a stay is not warranted for the sole reason that judicial review is to be sought. The requirements for a stay were outlined by the Court of Appeals in *Virginia Petroleum Jobbers Association* v. *F.P.C.*, 259 F. 2d 921 (CADC, 1958), a decision which has been followed generally by the other circuits[39] and which was cited with approval by the Supreme Court in the *Permian Basin Area Rate Cases*, 390 U.S. 747 at 773. These requirements are: (1) that the petitioners make a strong showing that they are likely to prevail on the merits: (2) that irreparable injury will result to the petitioners absent a stay: (3) whether the issuance of a stay will substantially harm other parties to

the proceeding: and (4) the effect of a stay on the public interest. Reviewing the various arguments advanced in support of stay, it is our opinion that the petitioners have not demonstrated that any injuries they might suffer in the absence of a stay would be irreparable and would out-

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[38] Sun Oil Co., the Hunt Group, Bradco Properties, Inc., *et al.*, the Amerada Group, Southeast Gas Producing Co., Inc., E. Cockrell, Jr., Forest Oil Corp., The California Co. and Samedan Oil Corp. The motions are opposed by the Associated Gas Distributors Group.

[39] *Eastern Air Lines* v. *C.A.B.*, 261 F. 2d 830 (CA2, 1958); *Hamlin Testing Laboratories* v. *S.E.C.*, 337 F. 2d 221 (CA6, 1964); *Associated Securities Corporation* v. *S.E.C.*, 283 F. 2d 773 (CA10, 1960); *Tennessee Gas Transmission Co.* v. *F.P.C.*, 283 F. 2d 729 (CA5, 1960).

weigh the irreparable injury to the public from the granting of the motions.[40]

None of the parties seeking stay of the order has even attempted to make a showing that any is likely to prevail on the merits. While conceding that as a result of the judicial affirmation of *Permian*, numerous issues are no longer open to question, and agreeing that the record is more complete than was made in that case, they point to the departures made from the Commission's action in *Permian* and challenge the adequacy of the support on which the additional findings are based. Taken together, the allegations constitute no more than a statement that there are issues which have not been settled in the *Permian* litigation and that are properly subject to court review. We agree. However, there is no support for the claim that there is a strong likelihood of upsetting or of substantially modifying the order issued in this proceeding.

Petitioners for stay contend that they will be exposed to the threat of irreparable injury by an immediate rate reduction in that the Commission would be unable to afford adequate relief from the resulting loss of revenues. If the order is reversed on the merits, the producers would not be precluded from recovering the difference between the rates collected and the rates which the producers should have been permitted to collect. Interim reductions in rates under an invalid order would not affect a producer's contract right to be made whole. Further, in the event of judicial reversal the Commission would have adequate authority, including the power to adjust future rates, to take

[40] Although both the Amerada and Hunt groups complain of the ordering of substantial refunds, no refunds have in fact been ordered at this time. The order (paragraph (G)) expressly provides that all amounts shown in the refund reports are to be held by the producers "subject to further order of the Commission" regarding their disposition.

any necessary corrective action to protect not only the producers but also the pipeline purchasers.

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In any event, even a showing of irreparable injury would normally not be sufficient in itself to warrant a stay when the assorted advantantages thereof are outweighed by the detriment to the public. As the courts have held, the effect of a stay on other interested parties and the public interest are of at least equal significance to the impact on private parties of its denial. In this case, grant of stay would mean the continued collection of rates which we have found, after careful consideration, to be excessive. Even if all such amounts were subject to refund requirements, it is well recognized that the protection afforded through the refund procedure will not give full protection to the ultimate consumers. *F.P.C.* v. *Tennessee Gas Transmission Co.*, 371 U.S. 145, 154-155; *F.P.C.* v. *Hunt*, 376 U.S. 515, 524-525.

To compel rate payers to continue to pay excessive rates and charges is contrary to the primary aim of the Natural Gas Act to protect consumers.[41] The issuance of a stay in these proceedings would defer for an extended period rate reductions which are already long overdue. Most of the rates here involved are not subject to refund but are subject to prospective reduction only. Further delay in accomplishing these reductions will harm other parties to the proceedings, not only by causing the continuance of pipeline purchases at a level of prices well in excess of the determined just and reasonable rates, but could well lead to the filing of additional pipeline rate increases.

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[41] *Hope Natural Gas Co.* v. *F.P.C.*, 320 U.S. 591, 610 (1964); *Atlantic Refining Co.* v. *Public Service Commission of New York*, 360 U.S. 378, 388 (1959); *Sunray Mid-Continental Oil Co.* v. *F.P.C.*, 364 U.S. 137, 147 (1960).

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By our October 23, 1968 order we amended the time schedule for the filing of the supplements necessary to bring the rate schedules into conformity with the applicable base area rate to 15 days after the issuance of the present order. In accordance with the request made by the Amerada Group, we are herein extending this time limitation to 30 days after the date of this order.

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Considering the circumstances that almost all of the issues raised in this case by the producer-respondents were present in *Permian* and were found on judicial review to be without legal merit, the strong probability that any revenue reductions occasioned by the decision can be offset or recouped should the Opinion and Order be held invalid, that no refunds are now being ordered, and that the issuance of a stay almost certainly will produce irreparable harm to other parties and the public in general, we conclude that the motions for stay should be denied in all respects.

New York Commission Motion

On January 8, 1969, the New York Public Service Commission filed a statement requesting that the Commission not take account herein of a letter dated December 16, 1968, from the President of the American Gas Association, referring to a possible "impending shortage" of natural gas and proposing certain actions by the Commission, on the ground that the letter is an "off-the-record" communication. The A.G.A. letter is not in terms addressed directly to the Southern Louisiana proceeding and does not bear the Commissions' docket number, AR62-1, *et al.*, which has been given the proceeding. The letter is not part of the

record made in this case and, consequently, the Commission has not based any part of its decision thereon.

The Commission finds:

(1) The applications for rehearing and accompanying or principles of law which either were not fully considered motions filed in these proceedings set forth no new facts by the Commission when it adopted Opinion No. 546 and accompanying order, or which new being considered warrant any change in or modification of such order, except as set forth herein.

(2) Good cause has not been shown either for reopening these proceedings for the receipt of additional evidence, as proposed by the Hunt Group, or for the scheduling of further oral argument.

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The Commission, acting pursuant to Sections 4, 5, and 16 of the Natural Gas Act (52 Stat. 822, as amended, 823, 830, 15 U.S.C. 717c, 717d. 717o) and sections 553, 556 and 557 of Title 5 of the United States Code (the Administrative Procedure Act, 60 Stat. 238, 239, 241, 242, as codified September 6, 1966 by 80 Stat. 383, 384, 386, 387) *orders*:

(A) Ordering paragraph (A) of the order accompanying Opinion No. 546, amending Part 154 of the Commission's Regulations Under the Natural Gas Act, is amended by adding a new subsection (g) after subsection 154.105(f) to read as follows: (g) notwithstanding the provisions of subparagraph (f), in the case of sales of gas-well gas sold or to be sold pursuant to contracts dated on or after October 1, 1968, which are limited to a base area rate of 18.5 cents per Mcf, the proscription on the filing of contractually authorized increases should not prohibit the filing of rate increases up to a base area rate of 20 cents per Mcf.

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(B) The moratorium on increased rate filings, above the rate authorized in Opinion No. 546, for gas produced within the taxing jurisdiction of Louisiana under contracts dated on and after October 1, 1968, will expire on January 1, 1974.

(C) Any producer who, within 30 days of the date of issuance of this order, files a petition for special relief by reason of the fact that it is transporting, or paying for the transportation of, gas produced outside the taxing jurisdiction of the State of Louisiana to a point onshore, may, with regard to the rate schedule supplement required to be filed by ordering paragraph (D) of Opinion No. 546, file a rate reflecting the applicable onshore base area rate established by ordering paragraph (A) of the Opinion for such production. The difference between the onshore and offshore rate shall be subject to refund as to all or any part thereof to which the producer ultimately is found not to be entitled. The authorization to collect the onshore rate shall continue until the Commission has acted on the petition for special relief or until it otherwise orders. The petition shall set forth the facts regarding each case as required by the Opinion herein. Where the petition for special relief is not filed within 30 days from the date of this order the Commission will issue such order as it believes necessary to protect the producer during the pendency of the consideration of its petition.

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(D) Special relief is hereby granted to Union Oil Company of California with regard to the sales of gas made under its FPC Rate Schedule No. 120, whereby Union is permitted to charge and collect up to 17 cents per Mcf, with appropriate Btu adjustment, if any, plus the actual

transportation charge paid by Union to the Jupiter Corporation, such additional amount currently being one cent per Mcf. The supplement to Rate Schedule No. 120 to be filed by Union shall so provide.

(E) Special relief is granted to the producers listed in Appendix B to this Opinion and Order. Such producers are permitted to charge and collect up to 18.5 cents per Mcf, plus Btu adjustment, if any, and subject to the quality standards and adjustment provisions set out in Opinion No. 546 and No. 546-A, for all sales of gas-well gas (including residue gas derived therefrom) made in the cited dockets, to the same effect as though the contract dates for such sales had been shown to be on or after October 1, 1968.

(F) The application for special relief filed by Signal Oil and Gas Company is denied.

(G) The effective date of Opinion No. 546 and its accompanying order is hereby changed to October 1, 1968.

(H) For the purposes of ordering paragraph (A) of the order accompanying Opinion No. 546, the term "contracts dated" shall be held to mean that date which appears on or within the gas-well gas sales contract. Such date shall be used to determine which of the area base rates is applicable to the particular sale.

(I) Section 154.105(d)(vii) of the Commission's Regulations Under the Natural Gas Act, as established in ordering paragraph (A) of the order accompanying Opinion No. 546, is amended to read as follows:

> (vii) Delivery Pressure — The gas shall be delivered at a pressure sufficient to enter the buyer's pipeline, except that when the natural flowing pressure of seller's wells declines to, or below, the level suffi-

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cient for such delivery nothing herein shall require seller to deliver gas at a pressure higher than specified by contract.

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(J) Ordering paragraph (C) of the order accompanying Opinion No. 546 is amended by striking from the last two lines thereof "in a final, unconditioned permanent certificate previously granted for such sale" and substituting in place thereof "by final order no longer subject to judicial review permanently certificating the sale in question and containing no refund condition." The motion for further clarification addressed to this issue is denied without prejudice.

(K) No interest shall be required on refundable amounts paid over to the Federal and State governments in royalties, except as and to the extent that such authorities pay interest to the producer when refunding overpayments of royalties. Interest due on refunds required under ordering paragraph (F) of the order accompanying Opinion No. 546 shall be calculated to the last day of the month preceding the month in which the refund report is required and is filed.

(L) The motion filed by the Hunt Group to reopen the record in these proceedings for the receipt of additional evidence is denied.

(M) The motions for reopening and consolidation of this proceeding with the proceeding instituted in Docket No. AR69-1 are denied.

(N) The motions for stay of Opinion No. 546 and its accompanying order are denied; the time limitation for the filing of rate schedule supplements required by order-

ing paragraph (D), previously amended to require such filings to be made within 15 days after the date of this order, is extended to 30 days after the date of issuance of this order. The time limitations for the filings required by ordering paragraphs (E) and (F) are extended, respectively, to 60 and 90 days after the date of issuance of this order.

(O) Appendix A, Part II of Opinion No. 468, as amended by Errata Notice issued October 31, 1968, is hereby further amended as follows: delete "Pan American Petroleum Corporation (Oper.), *et al.*, G-19641, G-19765, RI63-138."

(P) The request for further oral argument in these proceedings is denied.

(Q) Except as herein granted, the assignments of error addressed to Opinion No. 546 and its accompanying order are denied.

(R) The Secretary shall cause prompt publication of the findings and ordering paragraphs, together with notice of the availability of this entire Opinion and Order on Rehearing, to be made in the Federal Register.

By the Commission. Commissioner Carver dissenting filed a separate statement appended hereto.

(SEAL)

Gordon M. Grant,
Secretary.

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APPENDIX A

I. Parties Filing Application For Rehearing

Indicated Respondents (Amerada Group):

Amerada Petroleum Corporation
Atlantic Richfield Company
Cabot Corporation
Cities Service Company
Cities Service Oil Company
Columbian Carbon Company
W. H. Cocke
Continental Oil Company
Falcon Seaboard Drilling Company
J. R. Frankel
Gas Gathering Corporation
General American Oil Company of Texas
General Crude Oil Company
Getty Oil Company
Gulf Oil Corporation
The British-American Oil Producing Company
Estate of William G. Helis
Humble Oil & Refining Company
Kerr-McGee Corporation
Marathon Oil Company
J. Ray McDermott & Company, Inc.
Midwest Oil Corporation
Mobil Oil Corporation
Newmont Oil Company
Ocean Drilling & Exploration Company
Pan American Petroleum Corporation
Phillips Petroleum Company
Shell Oil Company
Sinclair Oil Corporation
Sohio Petroleum Company
Sunray DX Oil Company
The Superior Oil Company
Tenneco Oil Company
Texaco Inc.

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Union Oil Company of California
Agnes Cullen Arnold and Isaac Arnold, *et al.*
Austral Oil Company Incorporated
Perry R. Bass (Operator), *et al.*
Alco Oil and Gas Corporation

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The California Company, a Division of Chervon Oil Company
Hunt Oil Group:
Hunt Oil Company
Hassie Hunt Trust
H. L. Hunt
W. H. Hunt
Lamar Hunt
Caroline Hunt Sands
William Herbert Hunt Trust Estate
Claude M. Langton, Trustee
Secure Trusts
Lyda Hunt-Caroline Trusts
Lyda Hunt-Bunker Trusts
Lyda Hunt-Lamar Trusts
Lyda Hunt-Herbert Trusts
Lyda Hunt-Margaret Trusts
Placid Oil Company
Mobil Oil Corporation
New York Public Service Commission
Samedan Oil Corporation
Sea Robin Pipeline Company
Municipal Gas Distributor Group
The Superior Oil Company
Forest Oil Corporation
Shell Oil Company
Texaco Inc.
Distributor Interveners:
Central Hudson Gas and Electric Corporation
Consolidated Edison Company
Delmarva Power & Light Company

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Long Island Lighting Company
Pennsylvania Gas & Water Company
Philadelphia Electric Company
Philadelphia Gas Work,
Division of UGI Corporation
Washington Gas Light Company
Union Texas Petroleum, a Division of Allied Chemical Corporation
E. Cockrell, Jr.
Sun Oil Company
Southwest Gas Producing Company, Inc.

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Bradco Properties, Inc., *et al.*:
Bradco Properties, Inc.
Freeport Oil Company, Division of Freeport Sulphur Company
John W. Mecom
Lake Washington, Inc.
U. S. Oil of Louisiana, Ltd

Pipeline Group:
Southern Natural Gas Company
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Transcontinental Gas Pipe Line Corporation
Trunkline Gas Company
United Fuel Gas Company, *et al.*

Tennessee Gas Pipeline Company, a Division of Tenneco Inc.
Atlantic Richfield Company
Texas Gas Exploration Corporation
Sinclair Oil Corporation
Signal Oil and Gas Company

II. Parties Filing Motions For Clarification

General American Oil Company of Texas
Continental Oil Company

Union Oil Company of California
The Superior Oil Company
Tennessee Gas Pipeline Company, a Division of Tenneco Inc.

III. Parties Filing Motions For Stay

Hunt Oil Group
Samedan Oil Corporation
The California Company
Amerada Group
Sun Oil Company
E. Cockrell, Jr.
Southwest Gas Producing Company, Inc.
Bradeo Properties, Inc., *et al.*
Forest Oil Corporation

Opposition to Motion for Stay
Associated Gas Distributors

IV. Parties Filing or Supporting Motions to Reopen

Hunt Oil Group
Producer Respondents
Sun Oil Company
Phillips Petroleum Company
Consolidated Natural Gas System
Mobil Oil Corporation
Independent Natural Gas Association of America
Pipeline Group
United Gas Pipe Line Company
The Superior Oil Company

Parties Opposing Motions to Reopen
Associated Gas Distributors
Georgia Public Service Commission
Public Service Commission of New York
Municipal Distributor Group

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V. Parties Filing or Supporting Request For New Investigation

Public Service Commission of New York
Consolidated Edison Company

Parties Favoring New Investigation and Consolidation With Reopened Proceeding
Producer Respondents
Hunt Oil Group (Joinder)
Sun Oil Company (Joinder)
Phillips Petroleum Company (Joinder)
Consolidated Natural Gas System
Mobil Oil Corporation
United Gas Pipe Line Company
Pipeline Group
Independent Natural Gas Association of America

VI. Parties Filing or Supporting Motion for Further Oral Argument

Pipeline Group
Michigan Wisconsin Pipe Line Company
Tennessee Gas Pipeline Company
Consolidated Natural Gas System Companies
Kentucky Public Service Commission
The Superior Oil Company
Florida Gas Transmission Company

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Mississippi Public Service Commission
Public Service Commission of Indiana
Bradco Properties, Inc., *et al.*
E. Cockrell, Jr.
Producer Respondents

Oppositions to Motion for Further Oral Argument
Distributor Intervenors:

Consolidated Edison Company of New York, Inc.

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Long Island Lighting Company
Philadelphia Electric Company
Philadelphia Gas Works, Division of UGI Corporation
UGI Corporation
Washington Gas Light Company
Municipal Gas Distributor Group
New York Public Service Commission

VI. Petitions to Intervene

Sea Robin Pipeline Company (granted)
Signal Oil and Gas Company (granted)
Independent Natural Gas Association of America (granted)

Producer		Pipeline Purchaser		Contract Date	Filing Date Producer Application
Docket Nos.	Name	Docket No.	Name		
CI69-172	Pan American Petroleum Corp.	CP69-51	Transcontinental Gas Pipe Line Corp.	8-1-68	8-19-68
CI69-181	"	"	"	"	"
CI69-183	"	"	"	"	"
CI69-184	"	"	"	"	"
CI69-266	Shell Oil Co.	CP69-52	Texas Eastern Transmission Corp.	8-27-68	9-13-68
CI69-242	Shell Oil Co.	CP69-45	Southern Natural Gas Co.	8-27-68	9-4-68
CI69-231	Pan American Petroleum Corp.	CP69-48	Sea Robin Pipeline Company	8-21-68	9-3-68
CI69-232	The Offshore Co.	CP69-48	Sea Robin Pipeline Company	8-26-68	9-3-68
CI69-256	Union Producing Co.	CP69-48	Sea Robin Pipeline Company	8-26-68	9-9-68
CI69-259	Texaco Inc.	CP69-48	Sea Robin Pipeline Company	8-29-68	9-9-68
CP69-47	Southern Natural Gas Co.	CP69-48	Sea Robin Pipeline Company	8-26-68	8-30-68
CI69-293	Shell Oil Co.	CP69-90	Michigan-Wisconsin Pipe Line Co.	8-30-68	9-23-68

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Docket No. AR61-2, et al.

APPENDIX C
Sheet 1

ALTERNATIVE DISCOUNTED CASH FLOW TEST OF THE DETERMINED COST OF WELLHEAD PRODUCTION OF NON-ASSOCIATED GAS, RECALCULATING APPENDIX D, TABLE 1 OF OPINION 546, COLUMNS 9, 10 and 11 TO REFLECT INTEREST EXPENSE AS A TAX DEDUCTION

Year	Total Producer Gas And Liquid Revenue c (5)	Investment Outlay c (7)	Current Production Costs c (8)	F.I.T. Liability c (9)	Net Cash Flow c (10)	Discounted Present Worth at 12% c
1951		0.139832		-0.046175	-0.093657	-0.259720
1962		0.004494		-0.002139	-0.002345	-0.005806
1953		0.006764		-0.009728	0.002964	0.006553
1954		0.012388		-0.001653	-0.010735	-0.021189
1955		0.072876		-0.018300	-0.054576	-0.096179
1956		0.050296		-0.005160	-0.045136	-0.071021
1957		0.234860		-0.023489	-0.211371	-0.296955
1958		0.405112		-0.113900	-0.291212	-0.365296
1959		0.421000		-0.166647	-0.254352	-0.284875
1960		0.933976		-0.300346	-0.633630	-0.633630
1961	0.671874	0.940116	0.280998	-0.303113	-0.246127	-0.219767
1962	0.724173	0.366184	0.302667	-0.077247	0.132569	0.105684
1963	0.773790	0.196424	0.323637	0.015630	0.238099	0.169479
1964	0.823407	0.157148	0.344607	0.031244	0.290408	0.184554
1965	0.869001	0.098540	0.363480	0.055927	0.351054	0.199188
1966	0.869001		0.363480	0.096684	0.408837	0.207117
1967	0.869001		0.363480	0.096684	0.408837	0.184917
1968	0.844911		0.353694	0.093747	0.397470	0.160538
1969	0.804327		0.336219	0.089671	0.378431	0.136462
1970	0.774621		0.324336	0.085890	0.364395	0.117335
1971	0.753171		0.315249	0.083605	0.354317	0.101866
1972	0.735681		0.307560	0.081988	0.346133	0.088852
1973	0.721491		0.301968	0.080107	0.339416	0.077794
1974	0.708951		0.296376	0.079017	0.333558	0.068246
1975	0.698391		0.292182	0.077646	0.328563	0.060028
1976	0.689151		0.287988	0.076908	0.324255	0.052886
1977	0.680901		0.285192	0.075413	0.320296	0.046635
1978	0.581442		0.243252	0.064646	0.273544	0.035561
1979	0.498735		0.208302	0.055758	0.234675	0.027246
1980	0.425394		0.178245	0.042052	0.200097	0.020750
1981	0.365793		0.153081	0.040627	0.172085	0.015935
1982	0.312216		0.130713	0.034630	0.146873	0.012132
1983	0.268686		0.112539	0.029758	0.126389	0.009328
1984	0.229509		0.095763	0.025741	0.108005	0.007118
1985	0.197037		0.082482	0.021864	0.092691	0.005450
1986	0.142146		0.059415	0.015851	0.066880	0.003511
1987	0.123372		0.051726	0.013618	0.058028	0.002722
1988	0.104598		0.044037	0.011385	0.049176	0.002060
1989	0.087165		0.036348	0.009795	0.041022	0.001534
1990	0.073756		0.030756	0.008288	0.034711	0.001159
1991	0.063027		0.026562	0.006837	0.029628	0.000883
1992	0.054981		0.023067	0.006056	0.025858	0.000688
1993	0.046935		0.019572	0.005275	0.022088	0.000526
1994	0.038889		0.016077	0.004494	0.018318	0.000388
1995	0.033525		0.013980	0.003768	0.015777	0.000298
1996	0.026820		0.011184	0.003014	0.012622	0.000213
1997	0.024138		0.009786	0.002959	0.011393	0.000172
Total	16.710000	5.240000	6.990000	0.463680	5.216320	-0.138630

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End	Revenues (1)	Current Production Costs (2)	Interest on Long Term Debt (2a)	Accounting Charges (3)	Taxable Income	Federal Income Tax Liability
	c	c	c	c	c	c
1981			0.011072	0.065125	-0.046187	-0.046187
1982			0.000352	0.004104	-0.004456	-0.002134
1983			0.000544	0.019722	-0.020266	-0.010125
1984			0.000092	0.002551	-0.003443	-0.001720
1985			0.005760	0.032386	-0.038146	-0.019300
1986			0.004030	0.006751	-0.010781	-0.005360
1987			0.018592	0.030344	-0.048936	-0.023488
1988			0.052896	0.205197	-0.258093	-0.113600
1989			0.033344	0.313637	-0.346981	-0.138664
1990			0.013854	0.551736	-0.565590	-0.300346
1991	0.681856	0.280095	0.004464	0.942898	-0.631401	-0.303113
1992	0.724173	0.302867	0.028992	0.553446	-0.160932	-0.077264
1993	0.773740	0.323637	0.015552	0.402038	0.032563	0.015630
1994	0.823001	0.344607	0.012465	0.401260	0.065042	0.031220
1995	0.869001	0.363480	0.011695	0.361198	0.116514	0.055927
1996	0.869001	0.363480		0.304096	0.201425	0.096684
1997	0.869001	0.363480		0.304096	0.201425	0.096684
1998	0.866411	0.353694		0.305910	0.206807	0.099267
1999	0.804321	0.336219		0.281288	0.186814	0.089671
2000	0.774621	0.324336		0.271348	0.178936	0.085890
2001	0.753171	0.315249		0.263744	0.174178	0.083605
2002	0.735681	0.307460		0.257312	0.170849	0.082008
2003	0.721491	0.301368		0.252634	0.166489	0.079915
2004	0.708951	0.296376		0.247956	0.164619	0.079017
2005	0.698391	0.292182		0.244446	0.161763	0.077646
2006	0.689451	0.287958		0.240938	0.160225	0.076908
2007	0.680901	0.285192		0.238598	0.157111	0.075413
2008	0.581442	0.243252		0.203510	0.134680	0.064646
2009	0.498735	0.208302		0.174270	0.116163	0.055758
2010	0.425394	0.178245		0.149124	0.098025	0.047052
2011	0.365793	0.153081		0.128052	0.084640	0.040627
2012	0.312216	0.130713		0.109356	0.072145	0.034630
2013	0.268686	0.112539		0.094152	0.061995	0.029757
2014	0.229509	0.095763		0.080118	0.053628	0.025741
2015	0.197037	0.082482		0.069006	0.045549	0.021864
2016	0.142146	0.059415		0.049708	0.033023	0.015851
2017	0.123372	0.051726		0.043226	0.028370	0.013618
2018	0.104598	0.044037		0.036842	0.023719	0.011385
2019	0.087165	0.036348		0.030410	0.020407	0.009795
2020	0.073755	0.030756		0.025732	0.017267	0.008288
2021	0.063027	0.026562		0.022222	0.014243	0.006837
2022	0.054981	0.023067		0.019298	0.012616	0.006056
2023	0.046935	0.019572		0.016374	0.010989	0.005275
2024	0.038889	0.016077		0.013450	0.009362	0.004494
2025	0.033525	0.013980		0.011696	0.007849	0.003768
2026	0.026820	0.011184		0.009356	0.006280	0.003014
2027	0.024138	0.009786		0.008188	0.006164	0.002959
Total	16.710000	6.990000	0.320000	8.434000	0.966000	0.463680

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CARVER, Commissioner, *dissenting:*

At eleven o'clock on the morning of September 25, 1968, the Commission's Secretary published Opinion No. 546, a document well over 200 pages in length, including appendices. Before five o'clock in the afternoon of the same day, the Secretary received from the New York Public Service Commission an "Application for Rehearing" of Opinion No. 546, assigning nine major errors, as follows: (1) applying a "new-gas" incentive rate for gas sold under any contracts entered into before the Opinion; (2) fixing a rate for 1961-1968 contracts (second vintage) above cost, including return; (3) adding an additional increment of 0.5¢ for gas sold under contracts dated after September 30, 1968 (third vintage); (4) allowing a non-cost addition of 0.8¢ for offshore gas, without specifying clearly the reason therefor, and for "double counting" of incentive and return allowance; (5) too high a rate of return; (6) failing to cost all gas, rather than gas-well gas alone; (7) making an allowance for gathering, when revenues assertedly more than offset costs; (8) giving weight to field prices, in-line prices, and the Commission's own Policy Statement, none of which has any part in the determination of just and reasonable rates; and (9) fixing a discriminatory rate, namely one higher than that allowed in the *Permian Basin Area Rate Case*, both cases being based on the same national cost figures.

Other petitions for rehearing, filed after intervals reflecting less prodigious feats of rapid comprehension of the Commission's Southern Louisiana Opinion, presented similar as well as different attacks upon the Commission's handiwork. The Amerada Group, for example, filed an "Application for Rehearing" exceeding one hundred print-

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ed pages in length, exhaustively analyzing Opinion No. 546; three full pages of the Table of Contents were required to detail the asserted error.

Neither the New York specification of nine errors, nor the Amerada encyclopedia of several dozen errors, have been answered seriatim in the Opinion on Rehearing. The new Opinion struggles through the tangle of large and small asserted errors, giving much attention to some, no attention to others, making some explanations, some corrections, some retractions, and many assertions of renewed certainty. The effective date of the Opinion

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is changed by a few days; an ambiguity about controlling dates for vintaging contracts is removed; special relief is granted related to the Commission-initiated speedup of filings of producer contracts associated with offshore pipeline expansions; and more explicit Commission intentions are spelled out with reference to such terms as "delivery point," certain contested situations, delivery pressures, refund provisions, future certificate action, and the like.

These "housekeeping" matters, although they require almost all of Opinion No. 546-A, are not central. The central import of Opinion No. 546-A is related to the issue of the sufficiency of the prices fixed in Opinion No. 546 to elicit sufficient gas supply. The Commission refuses to reopen the proceeding, or to readjust price level, and yet, paradoxically, it does react to the insistent contention of almost all the filings which followed the issuance of Opinion No. 546, and the sole subject matter of many of them, by modifying the impact of its price determinations in a major way. It has precipitately started a new proceeding before the ink is dry on the old one.

It is not necessary to evaluate the pleadings which make the point of a gas supply shortage because the Commission in Opinion No. 546-A effectually concedes that a valid issue has been tendered, requiring far-reaching action. This action takes the form of a new and separate proceeding, the outlines of which are spelled out in Opinion No. 546-A. Furthermore, as will be amplified hereafter, the new proceeding is inextricably intertwined with this case. In practical effect the Commission may have reopened the whole Southern Louisiana proceeding AR61-2.

I must dissent in this case, but I heartily concur that a serious problem of gas supply has been identified, requiring action *in this case*. I do not believe that the new proceedings discussed in Opinion No. 546-A, and concurrently initiated, are appropriate and consistent with the public interest. A more appropriate procedure is open to the Commission, whose validity and superiority I shall try to demonstrate.

The Supply Issue

Although the Commission asserts (p. 2) that "[n]o probative showing, based on the record before us, has

been made in any such pleadings [i.e. subsequent to Opinion No. 546] indicating that the prices we have established will be inadequate to bring forth the optimum degree of effort by the industry," its next sentence belies such assurance:

> However, the pleadings do lead us to the conclusion that the vital importance of future additional gas supply from the offshore areas in Southern Louisiana warrants the immediate commencement of the further

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proceeding we had contemplated in our original Opinion herein looking towards a possible revision of the area price ceilings for such gas.

The pleadings now before the Commission reveal a crescendo-like pattern of reaction to Opinion No. 546. To an extent, this indicates the desirability of applying a discount factor, but does not preclude our fairly and fully describing what the parties have said about the impact of the Opinion on the vital question of price as a function of eliciting adequacy of effort to assure future supply.

The first round of response, though relatively less urgent than some of the later filings, still presents the issue of the "incentive" function of the Southern Louisiana price determinations. The later rounds, variously couched as pleadings, offers of proof, and argument, dealt more with the "here and now" nature of a crisis in gas supply.

In the first category, the key arguments are that the determined prices, far from having a positive incentive factor, have a negative incentive or price rollback effect. Since the traditional trend lines for measuring adequacy of supply, namely reserves to production (RP) and findings to production (FP) ratios, are already in a declining mode, the argument is that a price rollback not only cannot cause a declining of the trend in these averages to reverse or level out, but on the contrary will cause them to accelerate. The Commission said in Opinion No. 546 that the ratio of new supply to net production of natural gas, both in the United States, and for the Southern Louisiana area, was not significant in helping to determine reasonable rates. I believe this was an erroneous and non-supported statement which should now be corrected.

A table in the petition for rehearing of the Amerada Group graphically portrays the trend of the FP ratio:

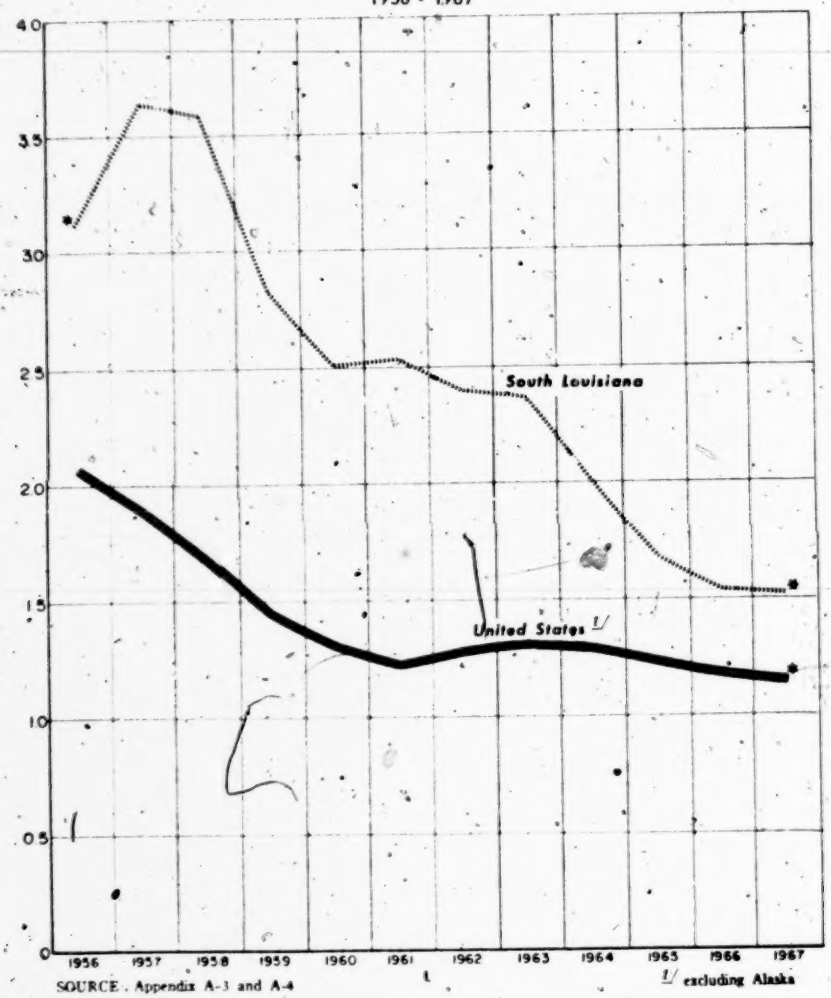
RATIO OF

NEW SUPPLY TO NET PRODUCTION OF NATURAL GAS

SOUTH LOUISIANA AND THE UNITED STATES

THREE-YEAR MOVING AVERAGE

1956 - 1967



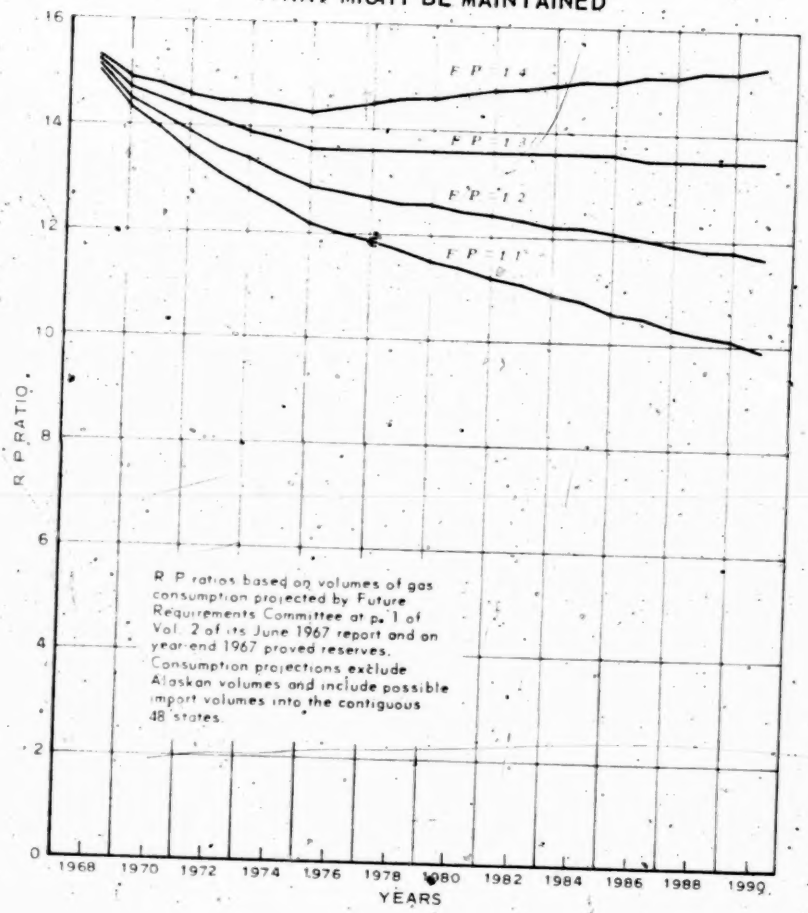
SOURCE. Appendix A-3 and A-4

*actual ratio for the year

1/ excluding Alaska

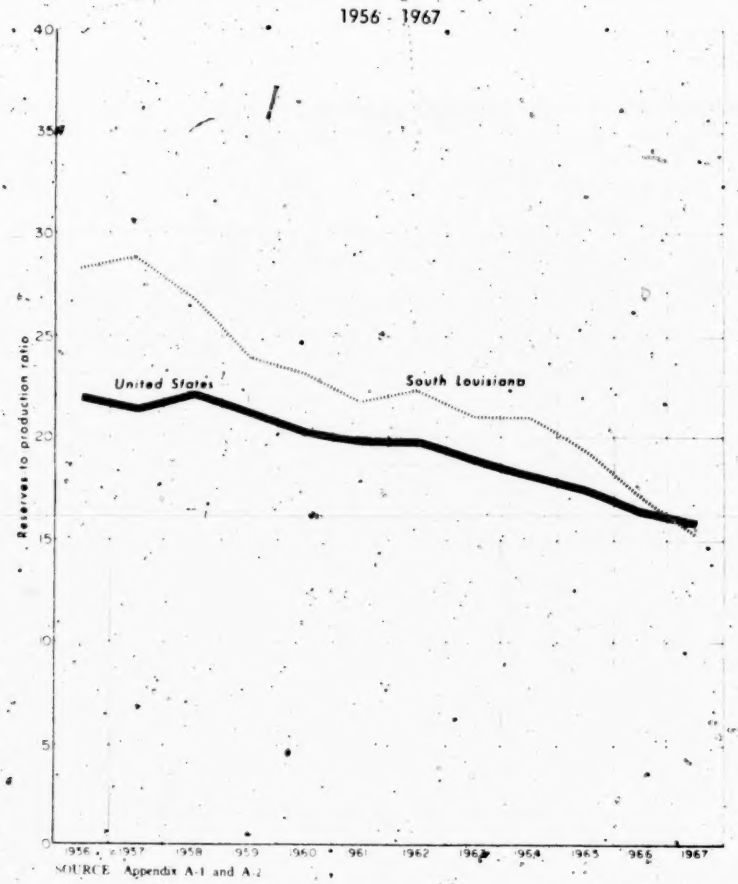
According to the American Gas Association figures for associated and non-associated gas, the FP ratio in 1967 was 1.2 to one and trending downward. The following graph illustrates the relationship. For example, at an FP ratio of 1.1, given the rate of growth projected by the Future Requirements Committee, the resulting RP ratio will have fallen in 21 years below 10.0.

PROJECTED TREND IN TOTAL RESERVES-TO-PRODUCTION RATIO FOR VARIOUS FINDING-TO-PRODUCTION RATIOS THAT MIGHT BE MAINTAINED



The Commission is faced with determining whether it can dismiss as purely speculative the critical supply situation which will surely eventuate if present supply and demand trends continue into the reasonably foreseeable future. The production of natural gas from the Southern Louisiana area, by record data, is increasing at a faster rate than reserve additions. In this circumstance the reserve to production ratio in Southern Louisiana declines each year faster than for the country as a whole, a fact graphically illustrated in the Amerada petition for rehearing:

TREND IN GAS RESERVES-TO-PRODUCTION RATIOS
SOUTH LOUISIANA AND THE UNITED STATES
1956 - 1967



SOURCE Appendix A-1 and A-2

1/ excluding Alaska

If the trend of reserves to production leads to a ratio of twelve to one, as seems likely, there will be an added dimension of the problem, namely deliverability. A lack of supply flexibility among and between producing areas will inevitably lead to higher consumer costs.

These are, as the producers say, stark facts. One possible answer may be for the Commission to state that the RP ratio ought to be allowed to decline an unspecified increment further, but the Commission (I think wisely) has not painted itself into such a corner. Nor do I find any of the distributors to have taken so extreme a position. The answer, if it can be called one, to the implication of these trends extended into the future, is the inference that the Commission really believes that there is no relationship between supply and price at all. This, at least, seems to be the thrust of the discussion on page 15 of Opinion No. 546, where it is said that "[h]igher prices might increase findings and lessen consumption."

In this country, where markets are traditionally free, and where price has always played an allocative function among competing fuels, or competing materials, price is assigned the function of producing equilibrium between demand and supply. A price so low as to create an excess of demand leads to shortage inevitably.

In economists' terms this is disequilibrium. The Commission's actions of starting the new proceedings concedes the disequilibrium, and attempts to correct it at once by lifting the moratorium for new contracts offshore. This will be discussed later in this dissent.

The second category of response to Opinion No. 546 is

found in the pleadings which contend that an immediate incipient supply crisis exists.

Consolidated Natural Gas System Companies, which in the aggregate is more a customer than a pipeline, made a motion for limited reopening of the proceeding. It offered to lay before the Commission what it called a serious problem currently existing as to the availability of gas for purchase in order to meet the increasing demands of the two million consumers dependent upon its system. After explaining that the ratio of reserves to

production has steadily declined, it states that

> . . . the worsening situation has been dramatically evident . . . during 1968 by the fact that we have not as yet been able to contract for large supplies essential to meet increases in consumer demands expected to come on our lines in 1970 and 1971.

In another poignant pleading, United Gas Pipe Line says that it is "vitally concerned with the decline in the relation of new supply to production in South Louisiana and with the apparent effect of the Commission's Opinion No. 546 to discourage the needed investment of funds by producers to meet the growth in demand for gas supplies in the South Louisiana Area."

A group of pipelines including Southern Natural, Texas Eastern, Texas Gas Transmission, Transcontinental, Trunkline and United Fuel Gas Company, emphasized that whereas *Permian* fixed a just and reasonable price above the theretofore effective guideline price, the Southern Louisiana price amounted to a rollback. In this context, "the risk of major difficulty is far greater if the determinations

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made in Opinion No. 546 prove inadequate because this area, unlike *Permian,* is the root source of a dozen major pipelines, for most of which there is no alternate supply area available to meet the increasing demands of their millions of consumers."

The distributors do not disagree in the matter of the importance of the area and of eliciting adequate supplies. In their conclusory paragraph, they state

> . . . there can be no question that the discovery and development of adequate new gas supplies in this area, and their commitment to interstate markets, are essential not only to the pipelines but to their distributor customers, and to the ultimate gas consumer.

Texaco, and associated producers, in asking for a reopening of the record and consolidation of the request for investigation of the adequacy of reserves, points out that in Opinion No. 546 the Commission "*reduced* flowing gas revenues rather than permit an *extension* of the

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existing firm rate structure [which] . . . is completely illogical in a time of extremely short supplies when regulatory policy should encourage rather than frustrate increased investments."

The New York Commission on January 9, 1969, filed with the Commission a "Request for Investigation" which was thereafter docketed as a separate proceeding RI69-470, and noticed for comment. Although that proceeding is technically separate from AR61-2, some of the parties herein have expressed the view that it would be more appropriate to have a limited reopening of the Southern Louisiana Area Rate Proceeding, and a motion to take such action is before the Commission.

The New York Commission, in that pleading, called attention to a letter of December 16, 1968, sent to the Commission's Chairman by the President of the American Gas Association, which letter was widely discussed in the press in terms of distributor concern about gas supply.

Second-Round Proceeding for Federal Domain

Opinion No. 546-A tries to tie the "second-round" proceeding, AR69-1, to Opinion No. 546 by referring to it as "the further proceeding we had contemplated in our original Opinion." As will be discussed *infra* at pages 14 *et seq.* this is not accurate, but at this point in this dissent, it is necessary to explain the particulars wherein Opinion No. 546-A, within its own four corners, modifies Opinion No. 546. To contend that the new proceeding stands on its own merits, and really does not amount to a modification of Opinion No. 546, is a logical sophistry, and an economic non sequitur. Indeed, it is doubtful that the Commission would even be attempting to appear to be reaffirming Opinion No. 546, if some tempering of its economic impact were not being accomplished.

What does Opinion No. 546-A give the producers, besides a free ticket to participate in a new proceeding which opens with the superstructure of an incorporated 34,000-page record?

In straight economic terms, the answer can be fairly forthright: in certain situations, producers.

are entitled to file for one and one-half cents more per Mcf than Opinion No. 546 calls for. The new price levels will be subject to refund, but not below a floor of 18.5¢.

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This additional "incentive" is bolstered by providing that ". . . if the Commission establish[es] a lower rate for fourth-vintage contracts than the third-vintage price, that lower rate will not be applied to deliveries thereafter made under third-vintage contracts." (Mimeo. p. 3, Commission Opinion.)

To demonstrate the economic or monetary dimension of these modifications, it is necessary to review the nature of the interim pricing structure, prior to the issuance of Opinion No. 546.

In 1960, the Federal Power Commission, reacting to the spur of the *CATCO* decision, *Atlantic Refining Co.* v. *Public Service Commission*, 360 U.S. 378 (1959), instituted a regulatory system designed to hold the price line in the public interest pending the conclusion of proceedings to fix just and reasonable rates on an area basis. Accordingly it promulgated standards, which came to have well established meaning as "guideline" and "in line" levels to help the Commission determine whether proposed initial rates in Section 7 certificate proceedings should be approved without a price condition, and whether rate changes should be accepted or suspended. The system is discussed generally in *Permian* at 390 U.S. 759 (1968) and by the Commission at pp. 131-134 of Opinion No. 546.

The calculations on pages 133 and 134 of Opinion No. 546 show the movement of the average effective rate both offshore and onshore. It was 19.99¢/Mcf as of January 1, 1965, as weighted by 1963 sales volumes, and moved upward to 20.06¢/Mcf using somewhat later data. At the same time, the effective rate was a little over 2¢/Mcf below the contract rates — in other words, price regulation since 1960 has held prices about 2¢/Mcf below the contract level.

It is important to remember, even though the point is

not mentioned in Opinion No. 546, that this interim regulatory structure administered between 1960 and 1968 in the Southern Louisiana area was explicitly designed to foster additional exploration which is also one of the objectives of the second-round proceedings.

Thus the Commission's promulgation in 1961 of a new guideline rate for Southern Louisiana was justified as being designed to enable the Commission to hold the line on new sales and ". . . *to enable producers to obtain authorizations which provide them a reasonable basis for proceeding with their operations, and furnishing needed supplies of gas.*" 26 F.P.C. 661, 662 (1961) (emphasis added).

The second-round approach extends the interim regulatory pattern, using it as an affirmative reaction to the gas supply contentions of the parties: There is, and clearly there is intended to be, an economic benefit to the producing segment of the gas industry, in this approach. The real question is whether this is the best available response to the problems presented.

Defects of the Second-Round Approach: The Question of Finality of AR61-2

Using the rehearing order in Southern Louisiana as the vehicle for announcing the opening of a "second-round" of area rate proceedings results in other important modifications of Opinion No. 546; one of them is possible protraction of the case itself.

Although the Commission certainly intends that Opinion No. 546-A shall be its final action in proceeding AR61-2, and now ripe for judicial review, this may not be the case.

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The area seaward from the boundary line of the area described in the new proceeding AR69-1, includes the operations of many producers who have been in the Southern Louisiana area proceeding, AR61-2, since its inception. These parties may feel themselves aggrieved by Opinions 546 and 546-A, and yet find themselves denied judicial review of their contentions on the ground that administrative finality as to them must be found in the new proceeding, AR69-1. Those producers in the area landward of the line may find their complaints about the location of the line judicially deferred until administrative finality attaches to the order fixing the line. Courts may be confused, as I am, as to whether the order fixing the line is final, and thus an appealable part of the order in AR61-2, not subject to further Commission action

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in AR69-1.

The consumer and distributor interests, particularly, may well find themselves frustrated in making objections to the creation of the new area, having no recourse except to get into the new proceeding and await possible refunds. Their contention, inferable from the petition for rehearing of the New York Commission, will surely be that this order setting up the new proceeding should be reviewed as an integral part of the presumably final order in AR61-2.

Defects of the Second-Round Approach: The Designation of the Area

Both Opinion No. 546-A and the "Order Instituting Investigation and Proposed Rulemaking" in Docket AR-69-1, Area Rate Proceedings Offshore Southern Louisiana, are devoid of findings to support the selected boundary demarking the new area. There is ample precedent, of

course, for the differentiation of areas in terms of dominion and taxing authority. But the findings for *cost* differences, other than the easily measured tax cost, are utterly missing — and area rate proceedings are supposedly concerned with costs.

Opinion No. 546 and Opinion No. 546-A adhere to a national costing methodology. The methodology of the costing in the new area is left very much in doubt and not shown to be factually related to any differences of a physical nature, affecting operating costs, lag between investment and production, or the unit costs during the build-up period.

Inconsistent with the findings of both the Examiner and the Commission in Opinion No. 546, the unity of the Southern Louisiana area from a cost and geological viewpoint has now been found not to exist.

It will be recalled that the Supreme Court, in its opinion sustaining the Commission in *Permian*, 390 U.S. 747, 787-90 (1968), on the question of the geographical areas selected in the 1960 Policy Statement, 24 F.P.C. 1121 (1960), commented on the fact that "no hearings were conducted, and no evidence taken, on the propriety of the areas thus designated by the Commission for inclu-

sion in the proceeding." In making this comment, the court "emphasized that the regulatory area . . . was evidently both convenient and familiar." But the Court also assumed that "the Commission now would, upon an adequate request, permit interested parties to offer evidence and argument on the propriety of modification of the Permian Basin regulatory area." In sustaining the Commission, the Court was

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careful to emphasize "the circumstances of this case," and concluded "that the Commission did not, *in these proceedings,* violate pertinent constitutional limitations, . . ." (emphasis added).

In a footnote, the Court noted that the cost and other data reflected national, and not area or local, circumstances.

Particularly in light of *Permian,* it would seem that the delineation of this new area for second-round proceedings has not been based upon requisite notice and findings.

An ambiguity exists with reference to whether, in the new proceedings, national or area costs will control. The Commission, by referring to the new proceedings as the one contemplated by Opinion No. 546, apparently opts for retaining the national costing base, for therein the Commission said (p. 130):

> In the circumstances, we believe that the question of offshore Louisiana costs should be again considered when further evidence is available with respect to *sales* in the far offshore zones, in conjunction with any later evidence with respect to *national* costs. (emphasis added).

The Commission's reference to "the further proceeding we had contemplated in our original Opinion herein looking towards a possible revision of the area price ceilings *for such gas,*" however, leaves unclear the antecedent of "such gas" in the quoted clause. In other words, does the Commission think that the original Opinion "looked towards" a possible revision of prices *only* for offshore gas as "offshore" is defined in AR69-1, or "offshore" in a more general sense? If the new proceeding is not the one generally referred to in Opinion

No. 546, and instead is one really considered for the first time in the rehearing phase, as I believe is the case, then moving from national costs to local or area costs is a major policy issue, deserving of more attention and discussion.

Defects of the Second-Round Approach: The Moratorium

It is true that there is another and express invitation in Opinion No. 546 for the filing of a petition to reconsider the area rates with respect to what is described on page 138 as the "far offshore situation."

Here is a double irony. Taken in context, that reference in Opinion No. 546 is to a situation and an area different from what is now designated in the caption of AR69-1 as "offshore Louisiana." On page 135 of Opinion No. 546, the Commission was considering prices "for gas produced in the *offshore area beyond the taxing jurisdiction of Louisiana*," (emphasis added) synonymous with the area now "barbered off" the Southern Louisiana proceeding. The invitation for further proceedings is found in the discussion beginning on page 136, and on page 138 a different term, "*far* offshore," is used. It is evident that the emphasis in that reference is on *far*.

The second irony is that the invitation for further proceedings occurs in the discussion on the indefinite moratorium on new filings, found in Opinion No. 546, and changed to a definite moratorium of five years for onshore third vintage volumes by Opinion No. 546-A. By way of supporting the indefinite moratorium imposed by Opinion No. 546, the Commission emphasized the following points (pp. 136-138):

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We believe that substantial price stability can and should be a principal objective of our determination in the public interest. . . . So far as can be determined from the evidence available to the Commission, the unit cost of finding and producing gas has continued to remain "remarkably steady."

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It appears, then, that just and reasonable rates, when established by the Commission, may be continued as the applicable ceiling prices for all gas produced in the area. Such rates may be made applicable not only to gas sold under contracts now before the Commission but also to any other gas sales hereafter made by any producer under any contracts whatever, including future contracts in the area.

• • •

On the other hand, we recognize that by imposing greater price stability requirements than in *Permian* we shall subject producers to some extra risk of a serious cost increase coupled with regulatory lag in adjusting prices to recognize the change. The risk is by no means absolute and is not excessive in the circumstances, as explained below, but it is a factor which we weigh in our overall rate determinations.

• • •

The risk is further lessened by the fact that the Commission will at all times be open to a petition to waive or lift the limitation on rate change filings in light of changed circumstances. Moreover, in the far offshore situation, which may give the most reason to question the accuracy of forecasts based on the present record, we expressly invite a petition to reconsider the area rates whenever sufficient evidence is presented to indicate a need for revision of the ceilings.

Generally speaking, however, we do not anticipate that changes will have to be made.

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These oft-repeated brave words now have a very hollow ring. The moratorium has been lifted entirely for the offshore areas, not *far* offshore areas, but all offshore areas not subject to Louisiana's taxing jurisdiction. Additionally, the indefinite moratorium so carefully

argued for in Opinion 546, is now a definite, five-year moratorium for third vintage onshore volumes.

The problems associated with the institution of these new, second-round proceedings appear to be many and obvious. Given the haste attendant upon its formulation and articulation, many more problems may appear. Of course it is probable that many or most of them could be worked out if the Commission took a more measured approach.

But however much I may disagree with this particular method of proceeding, I am in the heartiest accord with my colleagues in believing that immediate and meaningful action is indicated.

Incentive

Beginning at page 119 of Opinion No. 546 is a discussion of a settlement proposal. As discussed beginning at page 19, *infra*, I believe it would be preferable for the Commission to review that settlement in light of the considerations which have caused the Commission to start the new proceeding, AR69-1.

Before going into details, however, it is important to amplify the discussion on pages 10 and 11 *supra*, with respect to the interim pricing system, in order to demonstrate that Opinion No. 546, and Opinion No. 546-A to a

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lesser extent, contain a "negative-incentive" factor which militates sharply against the objective sought to be attained by the new proceeding.

As earlier stated, the Southern Louisiana guideline, established in October 1961, was calculated to provide the producers with a reasonable basis for proceeding with their operations, and furnish needed supplies of gas. The guideline price was 19.5¢, one cent higher than the just and reasonable level determined in Opinion No. 546.

For the areas within the taxing jurisdiction of Louisiana, a succession of past FPC decisions found the in-line price to be 18.5¢ plus 1.5¢ tax reimbursement, or a total of 20¢. Under Opinion No. 546, that is the figure for contracts entered into on and after October 1, 1968, or third-vintage gas; for gas under contract prior to that time, the price will be rolled back to 19.5¢ per Mcf for second-vintage gas (1961-1968) and to 18.5¢ per

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Mcf for first-vintage gas (pre 1961).

Applying calculations similar to those made at pages 131-134 of Opinion No. 546, and using the same data base, comparisons can be made, in "blended-price" terms, between the contentions of the various parties, the Examiner's pricing recommendations, the Commission's determinations in Opinion No. 546, and the pricing system proffered in

the settlement proposal discussed on page 119 of Opinion No. 546, as follows:

Source or Rate Pattern	Average Unit Price in Cents per Mcf
Philadelphia Electric Co.	15.68
Municipal Gas Distributors	15.69
Associate Gas Distributors	17.70
Staff	17.79
Examiner	18.26
Opinion No. 546	18.34
January 1, 1967, Last Firm Rates	19.01
Settlement	19.34
January 1, 1967, Effective Rates	20.06
January 1, 1967, Contract Rates	22.34

The effect of permitting filings higher by one and one-half cents per Mcf in the offshore area leads to a new effective rate figure, an upward bias of economic worth to the producers. This is the incentive aspect of the new proceeding.

Two things are quite clear. One is that the "incentive" aspect of the Commission's action is relative at best. The Commission has said, over and over, that the price fixed for third-vintage gas by Opinion No. 546 induces further exploration, but saying it does not make it a reality. There is a positive incentive only if the price yields a greater stream of revenue than the net amount the producer has been realizing prior to October 1, 1968; it is evident that there is no incentive, because it is lesser, not greater.

This anomaly will be tempered by lifting the moratorium offshore, thus continuing in effect the interim system of regulation. Permitting contracts to be entered into which carry rates higher than the just-prescribed

just and reasonable rate is an inducement or incentive only to the extent that there is furnished the basis to hope that some increment will eventually be found to be just and reasonable for the new, fourth-vintage gas. But the incentive is tainted from the outset, by reason of the rollback feature of Opinion No. 546.

It is faulty reasoning simply to dismiss past expenditures for exploration and development as having been "sunk." It is also questionable to assume that producers operated with an expectation that there eventually would be a price rollback, particularly in the light of the incentive language in the various guideline and certificate orders between 1961 and 1968. It is, of course, undeniable that the companies realized that they had an exposure to refund obligations, but this lesson cannot be wholly inferred from *Permian*, for in that case the just and reasonable rate for new gas was *higher* than the interim guideline. When the refund obligation becomes liquidated, it will inhibit the desire and willingness to expend for exploration and development. Price rollbacks, economically, are exactly equivalent to a reduction of future revenue realizations, whether with respect to first, second, or later vintage contracts. The revenue available for exploration and development is *pro tanto* diminished, and the incentive aspect of the price is correspondingly reduced.

By way of further amplification, it should be noted that revenues from flowing gas are as much a source of capital funds for new investments, as the revenues from new contracts. If funds otherwise available are reduced by approximately $50 million per year by the rate reductions of Opinion No. 546, and further reduced by refunds on the

order of $100 million or more (depending on how much longer delayed); the effect is, as one of the producers described it, "retroactive expropriation of the incentive which induced the initial commitment to interstate commerce." The psychological impact of granting permission to file for one and one-half cent higher rates offshore is bound to be regarded as somewhat illusory. Thus, the incentive value of the Commission's action is devalued from the outset.

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Settlement

In preceding sections of this statement, reference has been made to the settlement proposal discussed briefly at pages 119-123 of Opinion No. 546.

The table on page 17 *supra* shows there to be a one cent per Mcf differential between the "blended price" under the settlement, and the price under Opinion No. 546 before its modification by Opinion No. 546-A. Extrapolating the settlement to the sixth and eleventh years, that difference seems to widen, because the settlement proposal submitted to the Commission had escalation clauses in it.

	First Year	Sixth Year	Eleventh Year
Opinion 546	18.34¢	18.69¢	18.88¢
Settlement	19.34¢	19.91¢	21.18¢

The comparison starkly illuminates the trade-off between stability achieved by a settlement pattern, and the instability of Opinion No. 546 itself, modified as it has been by Opinion No. 546-A instituting the new proceeding.

To illustrate further the extent of the economic difference between the settlement pattern and the application of Opin-

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ion No. 546, a comparison can be made between the refunds which they would respectively call for. Using January 1, 1967 rates, and December 31, 1967 as an arbitrary date for comparison purposes (the passage of time would make the refunds relatively higher at about the same proportional rate), Opinion No. 546 would require refunds of $74 million, while the settlement would call for refunds of $59.7 million. (See pp. 131-134 of Opinion No. 546.)

Why then, prefer the settlement, if the differences are in such a narrow range? It is the burden of this dissent that there is a solid basis in the record to support approval of a pricing scheme substantially as set forth in the settlement proposal — not as acceptance of a settlement but rather, as the Commission stated its approach in Opinion No. 546 — by examining it independently. It is the further burden of this separate statement that it is superior policy to take such a course, to avoid the

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defects in the new second-round proceeding and the short-cut and abrupt method of its promulgation, and also to avoid the instability inherent in the new scheme, as demonstrated herein.

This recommendation is also based upon the conviction that the time has come for the Commission to take some risks for the sake of stability.

I do not believe that the record in AR61-2 needs reopening, or that additional hearings are indicated. However, I support the separate investigative proceedings advocated by the New York Commission, Docket RI69-470.

The record before the Commission supports fixing just and reasonable rates at the higher levels therein specified.

I further believe the record supports acceptance of the other components of that settlement, including the provisions with respect to moratoria, escalations, refund floors, vintage-determining criteria, and refund settlement procedures. For the purpose of this statement, I will discuss principally the bases in the record for the higher rate levels, since all the other matters are clearly within the Commission's legal prerogatives as established by judicial precedent.

Zone of Reasonableness

A modification of the allowed rates in our proceedings on rehearing must be considered inappropriate only if the Commission's cost findings are considered to be unalterable. They are not unalterable, as I believe will be demonstrated.

The Briefs on the 34,000 pages of transcript were monumentally extensive, with a recurrent theme of complaint by producers about the cumulative impact of the Examiner's and the Commission's denials of so many of their cost contentions. For illustrative purposes, I have selected a few of these moderately complex items for a more intensive personal reexamination. One of these is the calculation of the rate base with respect to new gas. Other cost components for both new and flowing gas have also been reviewed with the purpose principally to demonstrate the zone of reasonableness and the opportunities for amelioration of the impact of

Opinion No. 546 within that zone. I think this is a better basis for modifying Opinion No. 546 than the one selected by the Commission. My purpose emphatically is not to establish new and different precise costs to reach a price pattern of my own.

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To put it bluntly, the Commission can indeed validate the price recommendations of the settlement proposal as within the standards of Sections 4 and 5 of the Natural Gas Act.

The Depletion Period — 20 Years or 22 Years?

Turning first to a component which only relates to the rate base for new gas, both the Examiner and the Commission based their cost computations for new gas upon a theoretical "model" which assumed a 20-year depletion period. In other words, both adopted an investment rate base at an amount equal to ten years of capitalized findings costs, plus one year for lag.

This was the method adopted in *Permian,* and in following that precedent the Examiner placed heavy reliance on *Permian.* The Supreme Court's Opinion in *Permian,* 390 U.S. at 805-6, however, by no means foreclosed the adoption of a different model:

> We turn now to the Commission's computation of the proper rate base. The Commission's method here differed significantly from that frequently preferred by regulatory authorities. It did not use a declining rate base and return, but instead computed an average net production investment, to which it applied a constant rate of return. The Commission assumed for this purpose that a gas well depletes at a uniform rate, and that it is, on average, totally depleted in 20 years. It found that the annual capital-recovery cost, including depletion, depreciation, and amortization, was 3.95¢ per Mcf. Allowing one year for a lag between investment and first production, the Commission obtained an average production investment of 43.45¢ per Mcf. The proper return per Mcf was then calculated by multiplying this figure by the rate of return.

> The producers argue that this has the effect of postponing revenue, and thus discounting its present value; they suggest that the Commission should properly have employed a declining investment base and return. This is a question peculiarly within the Commission's discretion, and, while the method adopted by the Commission was evidently less favorable to the producers than various other possible formulae, we cannot hold that it was arbitrary or unreasonable.

Comparison of the evidence adduced in *Permian* and in Southern Louisiana on this issue reveals that the subject was accorded more attention in Southern Louisiana than it had been in the *Permian* proceeding. The distributors' witness, Mr. Herman G. Roseman, computed return on the assumption that gas findings are depleted at equal annual rates over a 20-year period (Item H, Tr. 14,678), but his approach, which had been relatively less vigorously challenged in *Permian*, was sharply contested in Southern Louisiana. The contentions of the producers with respect to this issue at the rehearing phase is that the Commission has itself clearly recognized the weakness of using a depletion period of 20 years in its own Opinion in *Permian* [34 F.P.C. 159 (1968)] by offsetting against the years of production beyond the 20-year period used in the model the relatively greater "output of gas and condensate during the first years of depletion." The Commission has chosen to ignore this particular line of argument, so I shall quote the language of Opinion No. 468 (34 F.P.C. at 199), which best shows the basic deficiencies both in the *Permian* record and in the Examiner's and the Commission's reliance on that record:

> A return must be allowed upon the investment for

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the average period of recoupment. Having determined the total production investment cost to be 3.95 cents per Mcf, the presiding examiner then estimated that the average period required for return of each dollar of that investment will be 10 years after the resulting gas begins to flow. He reached this conclusion by assuming that the gas will be totally depleted in 20 years, the normal life of a contract, and that the depletion will

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take place in an equal amount each year. The Major Producer Group and The Superior Oil Company contend that the true period of depletion is at least 22 years, and that this period rather than 20 years should be the basis of calculation.

These respondents are correct in pointing out that the period of well depletion is somewhat longer than 20 years. *More than offsetting, however, is the fact that wells are not depleted uniformly over their producing life. They produce a greater output of gas condensate during the first years of depletion.* Production usually begins to decline some 7 to 12 years after the well begins to flow until, during the last years of depletion, the well is producing only a fraction of its flow in earlier years. While exact figures are not available, it appears that the additional years of minimal production, not included in the examiner's computation, are more than offset by his computing depletion at an even rate rather than taking into account the higher production in early years and the greatly lowered production at the end of the period. Accordingly, the exceptions on this point will be denied. (Emphasis added).

The deficiencies which the Commission recognized and compensated for in the *Permian* proceedings with respect to the depletion model were handled somewhat differently

in South Louisiana. At page 37 of Opinion No. 546 the Commission resorts to fiat, perhaps circular fiat:

> Ten years or less *is in fact* the average period that capitalized investment is outstanding. We know that because the gross investment in producing properties is about twenty times the annual amount of depreciation, depletion, and amortization; in other words, the average property is produced over twenty years. The record figures for Appendix B producing gas leases (excluding shut-in leases) are $2,393,565,854 gross investment
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> and $133,223,254 annual DD&A. That *actually* indicates a production period of 18 years. Of course, many properties continue producing past the twentieth year. But this late production is at *relatively low volumes* compared to earlier years. And some properties play out quickly. *All in all,* the investment is *typically* written off over twenty years *or less. On the average* an Mcf waits, *at most,* ten years to be produced (some gas is produced in the first year, some in the twentieth, etc.; but the average is ten years or less). We allow a return for ten years of waiting. (emphasis added, footnote omitted).

This is a far less satisfactory way of handling a complex problem than the way adopted by the Commission in Opinion No. 468. The language of certitude is belied in the quotation itself, as the underscored adverbs tend strongly to indicate.

Yet, as stated, Opinion No. 546-A is silent on this particular problem, which silence may be quite purposeful in light of the impact of the combination of the evidence supporting a 22-year model, and its pricing implications.

Taking 20 years or 22 years as the depletion model is

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a way of stating certain assumptions. All parties agree that the actual depletion period is much greater. At considerable and persuasive length, the producers in their petition for rehearing undertake to demonstrate that even accepting the Commission's assumptions, the 22-year model is the more appropriate, emphasizing the time value of money in particular.

Apart from the tables submitted by the Amerada Group supporting a 22-year model as more appropriate, even with the Commission's set of assumptions, reference might additionally be had to Ex. 116, Schedule 10, and Ex. 42, Schedule I, Sheets 3 and 4, wherein it appears that both the intervenor witness and the staff witness project as much as a five percent depletion rate for eleven and thirteen years, respectively, of a thirty-five year productive period. This strongly argues that the offsetting theory of *Permian*, if valid there, is not valid in South Louisiana.

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The impact of adopting the 22-year model is to increase the rate base by ten percent, so that the return on the rate base would be augmented by 0.48¢ per Mcf.

Time Lag

Time lag is a somewhat related matter and pre-production time lag is discussed in Opinion No. 546-A. Rectification of the deficiencies of the *Permian* record on time lag was attempted in Southern Louisiana by an empiric study, introduced as the Auten-Davis study, Exhibit 248. Opinion No. 546 at page 39 appears to rely on that study:

> Looked at very closely, respondents' data in Exhibit 248 corroborate a finding of one-year's lag, as shown in the table on the next page.

However, in Opinion No. 546-A, this statement is modified, first by saying that the Commission had *not* based its time lag allowance on these data. This is a questionable premise; the above quotation from Opinion No. 546 is certainly not "arguendo" in form.

Second, and more substantively, the Commission now accepts a correction of the table on page 40, and also on the matter of the relevant center of the first year production, i.e., six months later than shown in Opinion No. 546.

These time-lag problems undoubtedly present a very difficult problem for the Commission, a difficulty resolved in *Permian* (Opinion No. 468) by bracketing contentions by some parties in favor of a "negative lag" with a discussion of the variation in the various components which are supposedly averaged into a time-lag model, and then concluding that after "taking into consideration the evidence of both the positive and negative lag, we believe that the presiding examiner's determination on this point should be upheld." (34 F.P.C. at 200.)

But there was an empiric basis for arriving at an

average figure for time lag, or time-lag model, which had been considered by the Examiner in his decision to be suspect (pages 60 to 64). The Commission now says that Opinion No. 546 "upheld the Examiner's findings and conclusion that the Auten-Davis data are not reliable proof and tend to exaggerate lags." (Mimeo. p. 29, Op. 546-A).

The Commission could well note, for the record indicates, that although the Auten-Davis data were requested by a covering letter which observed that "time is money," the conservatism of some of the data submitted, and indeed the

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conservatism of the overall result as compared to what had theretofore been the producer contentions, somewhat soften the effort to impeach the study. Furthermore, far from accepting the Examiner's impeachment of Exhibit 248, the Commission in Opinion No. 546 purported to rely on it.

All in all, the purpose of the Commission is highly defensive, in view of the fact that after years of hearings, and 34,000 pages of transcript, it has nothing better to rely on in the petition for rehearing of Opinion No. 546 than the discredited *Permian* precedent and the Commission ukase that "the Opinion No. 546 end result is still confirmed by the full timing studies." (Mimeo. p. 31, Op. 546-A).

To the contrary, I believe this is another area for application of a "zone of reasonableness" adjustment. If the objective is to find a better methodology than reopening Southern Louisiana, or than starting a new proceeding, then in dollars and cents terms, the addition of only .57 of a year would augment the rate by 0.28 cents per Mcf.

Drilling Costs

The Commission has an ample basis on the record to support the additional allowance, which approval of the figures contained in the proffered settlement would provide for both new and flowing gas. This can additionally be demonstrated by selecting representative items, and showing the extent of the "zone of reasonableness" and the nature of the Commission's choices within that zone.

One particularly glaring example is found in Opinion

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No. 546, page 27, where the Commission relies on its "own conclusions on the trend in unit costs" as a basis for reject-

ing the request that there be no downtrending in the 1958 Census drilling cost figures.

With apparent mathematical certainty, 1958 Census drilling costs were downtrended 5.8%. The Commission's "own conclusions" obviously do not provide the 5.8% factor. The figure selected traces to the "successful well" allowance, as to which there were four separate witnesses, as follows:

Witness	Sponsor	Estimate
Robert H. Park	Producers	2.94¢
Stephen F. Sherwin	Producers	5.30¢
Harold L. Spain	FPC Staff	3.28¢
Herman G. Roseman	Distributors	2.88¢

Witness Roseman's estimate of 2.88¢ was based on the 5.8% downtrending factor; reversing it would substitute a figure of 3.05¢ per Mcf for this item of cost, a net differential of 0.17¢ per Mcf. The producers also contended for revised footage figures which would have increased the figure to 3.10¢ per Mcf, or a total increase of 0.22¢ — still well below the estimate made by the Commission's own witness, Dr. Spain.

The calculation of the cost per successful gas foot in Opinion No. 546 was $16.89 (page 34). The record shows that the Joint Association Survey cost figure was $18.57. This would calculate to an additional allowance of 0.29¢ per Mcf.

Related Costs

These are extremely important calculations, deserving of far more attention than the Commission has given them on the rehearing phase. The Commission's slavish reliance on the Roseman costing model has meant that the seem-

ingly-precise figures for lease acquisition costs, production facilities costs, and other exploratory costs, are suspect, since in the Roseman methodology, these are estimated as percentages of successful well-costs. Consequently, the effect of making the adjustment in successful well-costs, as discussed above, would be additive in

each of the other items. In other words, an upward adjustment of 0.22¢ per Mcf in successful well-costs would lead to an increase of 0.09¢ in lease acquisition and other production costs. This would result in an increase of 0.31¢, from 4.04¢ to 4.35¢ in unit capitalized outlay, and hence to a 0.43¢ increase in return allowance.*

All of this is premised on staying with the Roseman methodology, with a total effect of 0.74¢ per Mcf, exclusive of the effect on return allowance argued at pages 21-24 of this dissent, and of the "growth" adjustment to exploration and development.

Exploration and Development — Growth Factor

Exploration and development costs have to be transformed from a calculation per-Mcf-found into a level appropriate per-Mcf-produced — in other words, the application of a ratio between exploration level and production level.

This is an area of judgment, transcending most of the other cost determinations, and the statement of the process illustrates the indefiniteness of the methodology. The ratio logically ought to be that dictated by the required rate of growth in production volumes, which, of course, is what

* Taking into account 1.57-year lag, as discussed on page 25 of this dissent.

the whole case at this stage is all about. For every one percentage point of annual growth in production volume deemed necessary, an added volume of reserves needs to be found twenty times as large (that is, equivalent to twenty percent of current production volume) — all this on top of the volume of reserves required to be found in full replacement of the current production volume. The 20% figure presupposes that new pools will be depleted no faster than 5% per annum.

Roseman calculated, and the Examiner and the Commission agreed, a growth allowance of thirty-seven percentage points, another way of saying that it provided for growth at a rate slightly under two percent.

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Growth in production of non-associated gas is running much higher than 2%, probably well over 5%.

Again simply following the Roseman methodology, but substituting a very conservative 5% rate of growth for non-associated gas, would yield an allowance higher by 1.90¢ per Mcf (from 1.12¢ to 3.02¢), exclusive of any upward adjustments in dry-hole costs or in other exploratory costs (the latter are estimated in Opinion No. 546 as a percentage function of successful well-costs, as above noted).

Dry Hole Costs

Similar to successful well-costs, the "dry hole" calculation was derived from testimony as to which there was variation among the witnesses as follows:

Witness	Sponsor	Estimate
Robert H. Park	Producers	1.58¢
Stephen F. Sherwin	Producers	2.30¢
Harold L. Spain	FPC Staff	2.08¢
Herman G. Roseman	Distributors	1.42¢

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The Commission followed Roseman, the lowest estimator, who used as underlying support an estimate of $9.31 per foot of dry-hole drilling costs, after making his own judgmental adjustment to Census data which showed $8.92. The 1960 Joint Association Survey figure was $10.56 per foot, and if that record figure were substituted, the allowance would be 1.61¢ per Mcf, still well below Staff witness Spain's estimate, and indeed lower than any witness except Mr. Roseman, whose estimate was accepted. The difference is 0.19¢.

Liquids Credit

Of all the areas of imprecision in cost-fixing methodology, none is more frustrating than the calculation of the liquids credit. On this item, the Commission selected a figure, 3.30¢, which was above that of witness Roseman which was 3.01¢. (This results in a lower price, since the higher the *credit* the lower the resulting figure). Dr. Spain based his estimate on questionnaire data, without adjustment for dissimilarity in incidence of condensate for nationwide, as opposed to questionnaire-

respondent experience, nor for any change in the incidence of condensate in newer as opposed to older reservoirs. The Examiner's credit was 3.05¢, and using his figure as the base, rather than Roseman's, an adjustment of 0.25¢ would result.

Precision

The discussion illustrates the fundamental unreliability of the seemingly-precise cost figures. An adjustment within a zone of reasonableness to accommodate to the settlement figures is clearly feasible.

Where, as here, we have an almost limitless complex of

variables, the Commission ought to rely on the adversary process as reflected in the settlement negotiations as a guide at least as reliable as the misleadingly precise calculations to which it is seemingly so firmly wedded. If the settlement pattern should be followed, it would be unnecessary to single out from among the variables those which exactly equal the given rates, but rather only to show the existence and scope of the zone of reasonableness. To me, it is beyond peradventure of doubt that the zone extends upward sufficiently far to make acceptance of the settlement far more in the public interest than the ill-considered new proceeding which the Commission has selected as an alternate approach.

Recapitulation

The various items singled out for discussion are additive as to new costs, i.e. second and third vintage. They are recapitulated, however, only to lay the foundation for the more limited conclusion which I draw from the analytical exercise:

Item	Impact in ¢/Mcf
22-year depletion period	0.48¢
Time lag of 1.57 years	0.28
Drilling costs — successful well	0.29
Related	
Lease acquisition	0.09
Return allowance	0.43
Unit capitalized outlay	0.31
Exploration and development	1.90
Dry Hole	.019
Liquids credit	0.25

I have no idea that all or any of these figures are precisely correct; I think the Commission and its staff has

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no better idea that the ones selected for Opinion No. 546 were precisely correct. Since the differential between the settlement figure and the result of Opinion No. 546 before modification were within one cent per Mcf, it is certainly evident that all of the above adjustments should not be accepted.

My purpose in reviewing the testimony and the contentions of the parties has been to show that in the methodology of the Commission there is most assuredly no such scientific accuracy as to prevent the making of adjustments, while remaining within the boundaries of judicially-supportable exercise of judgment.

If, however, I as one Commissioner had the responsibility of finding the exact rate level, I could not do it on this record, and I could not do it on the basis of any record that I can conceive of ever being made to this Commission.

That is why I am so opposed to opening a new proceeding, and that is why I am so drawn to the settlement route which has been followed and presented to us late in the proceeding.

Opinion No. 546 shows in several departures from the pattern of the *Permian* decision which bear close resemblance to suggestions made in the settlement (such as three vintages of gas) that the settlement proposal contributed to the decisional process. It is my belief that a retracing of our steps with reference to the settlement figures will more comport with the public interest than the new proceeding, second-round approach adopted.

Support for the Settlement

Though the settlement proposal was not a settlement, it did carry an impressive roster of support from all affected segments of the gas industry. Using 1967 sales as a base

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for calculating relative percentages, distributors favoring settlement account for 87% of the total volume, while those opposed accounted for 13% of the volume.

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Conclusion

This opinion expresses a disagreement with my colleagues on what is essentially a matter of Commission policy and procedure. Whereas the Commission believes that opening a second-round proceeding is the better way to respond to an identified and admitted problem related to the insufficiency of the price structure of Opinion No. 546 to elicit new supplies, I believe it preferable to revisit the record underlying Opinion No. 546. Therein I have found adequate support for an order consistent with the features of the settlement proposal presented to the Commission during the time when the Commission was reviewing the Examiners Decision in the case.

Nevertheless, there are a number of underlying legal questions contained within the policy disagreement. As disclosed herein, my analysis leads me to believe that AR61-2 may not be final; that the designation of the geographical area for the new proceeding is procedurally deficient and clouded with ambiguity; and that the modification of the moratorium provision and its lifting in this order may be prejudicial in a substantive way to parties to the proceeding.

To support my preference for the settlement pattern as a policy alternative, it has been necessary to review certain components of cost. That review has shown to me, more clearly, I confess, than I saw when Opinion No. 546 was under preparation, how important the data base is to the

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exercise of the expertise which Congress and the judiciary have accorded us. I have, therefore, discussed problems not treated in Opinion No. 546 or Opinion No. 546-A, such as the impact of the price rollback, or negative incentive features of Opinion No. 546, in light of the interim regulatory pricing scheme; the fallacy of considering already-executed contracts as being wholly "sunk" and thus not relevant to the question of incentive; and the separate and cumulative impact of the selection of low-end estimates in judgmental, or "zone of reasonableness" situations for such items as the depletion period, time lag, drilling and other related costs, the growth factor, dry hole costs, and liquids credit.

Permian stands for the idea that Southern Louisiana and other area rate cases subsequent to *Permian* should

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reflect a better quality of analysis. I think that Opinion No. 546 disappoints in this respect. The petitions for rehearing presented an opportunity to correct errors, and although some have been corrected, in the larger matter of costing ambiguities, Opinion No. 546-A is even more disappointing. My analysis of a selected group of the costing issues forces a conclusion that precision and certainty are simply not to be found.

We may share and sympathize with the "numbers" reaction expressed by the Court of Appeals, Tenth Circuit, in its consideration of *Permian* (375 F.2d 6, 24). But the "assumptions, allocations, formulae, equations, averages, means and calculations" so plaintively described by that Court are the grist of Commission responsibility. They ought not be left to staff expertise, but rather should be given the scrutiny their impact on the final result suggests.

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It has been my purpose to show how I think this should now be done. I believe the responsible way to save the area pricing methodology approved in *Permian,* and likewise to restore public confidence in it, is to adopt the recommendation which I have made, namely that the settlement pattern be relied upon as the best way to resolve the hundreds or thousands of various combinations and permutations which the record permits, all within a zone of reasonableness.

It is, at the very least, highly preferable to the Commission's "second round" approach, with its attendant legal questions and ambiguities. That approach sentences everyone concerned to endless litigation, during which, inexorably, administrative error of the kind I have discussed becomes binding precedent.

JOHN A. CARVER, JR.
John A. Carver, Jr., Commissioner

APPENDIX F

Statute Involved
Natural Gas Act, June 21, 1938
(52 Stat. 821-833; 15 USC § 717-717w)
Section 4
Section 5(a)
Section 7(c), (e)
Section 16
Section 19(b)

F. STATUTES INVOLVED

NATURAL GAS ACT: 15 U.S.C. § 717 et seq.

§ 717c. Rates and charges; schedules; suspension of new rates

(a) All rates and charges made, demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural-gas subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges, shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful.

(b) No natural-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Under such rules and regulations as the Commission may prescribe, every natural-gas company shall file with the Commission, within such time (not less than sixty days from June 21, 1938) and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection, schedules showing all rates and charges for any transportation or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and service.

(d) Unless the Commission otherwise orders, no change shall be made by any natural-gas company in any such rate, charge, classification, or service, or in any rule, regulation,

or contract relating thereto, except after thirty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the thirty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Whenever any such new schedule is filed the Commission shall have authority, either upon complaint of any State, municipality, State commission or gas distributing company, or upon its own initiative without complaint, at once, and if it so orders, without answer or formal pleading by the natural-gas company, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the natural-gas company affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect, and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of the suspension period, on motion of the natural-gas company mak-

ing the filing, the proposed change of rate, charge, classification, or service shall go into effect. Where increased rates or charges are thus made effective, the Commission may, by order, require the natural-gas company to furnish a bond, to be approved by the Commission, to refund any amounts ordered by the Commission, to keep accurate accounts in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts were paid, and, upon completion of the hearing and decision, to order such natural-gas company to refund, with interest, the portion of such increased rates or charges by its decision found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the natural-gas company, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible. June 21, 1938, c. 556, § 4, 52 Stat. 822; May 21, 1962, Pub.L. 87—454, 76 Stat. 72.

§ 717d. Fixing rates and charges; determination of cost of production or transportation

(a) Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification,

rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: *Provided, however*, That the Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company; but the Commission may order a decrease where existing rates are unjust, unduly discriminatory, preferential, otherwise unlawful, or are not the lowest reasonable rates.

§ 717f. Construction, extension, or abandonment of facilities; certificate of convenience and necessity; condemnation proceedings

(c) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefor, or acquire or operate any such facilities or extensions thereof, unless there is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: *Provided, however*, That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on February 7, 1942, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is made to the Commission within ninety days after Feb-

ruary 7, 1942. Pending the determination of any such application, the continuance of such operation shall be lawful.

In all other cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: *Provided, however*, That the Commission may issue a temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.

* * * * * *

(e) Except in the cases governed by the provisos contained in subsection (c) of this section, a certificate shall be issued to any qualified applicant therefor authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such

reasonable terms and conditions as the public convenience and necessity may require.

§ 717o. Administrative powers of Commission; rules, regulations, and orders

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this chapter; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed. Unless a different date is specified therein, rules and regulations of the Commission shall be effective thirty days after publication in the manner which the Commission shall prescribe. Orders of the Commission shall be effective on the date and in the manner which the Commission shall prescribe. For the purposes of its rules and regulations, the Commission may classify persons and matters within its jurisdiction and prescribe different requirements for different classes of persons or matters. All rules and regulations of the Commission shall be filed with its secretary and shall be kept open in convenient form for public inspection and examination during reasonable business hours. June 21, 1938, c. 556, § 16, 52 Stat. 830.

§717r.(b) Rehearing; Court review of orders

* * * * *

(b) Any party to a proceeding under this act aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the circuit court of appeals of the United States for any circuit wherein the natural-gas company to which the order relates is located or has its principal place of business, or in the United States

Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be transmitted by the clerk of the court to any member of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of title 28, United States Code. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part. No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings, which if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside,

in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States upon certiorari or certification as provided in [former] sections 239 and 240 of the Judicial Code, as amended (U.S.C., title 28, sec. 1254). June 21, 1938, c. 556, § 19, 52 Stat. 830